ENVIRONMENTAL ASSESSMENT

AIR QUALITY

Testimony of William Walters

SUMMARY OF CONCLUSIONS

The Orange Grove Project should comply with all applicable laws, ordinances, regulations, and standards and should not result in significant air quality impacts provided the recommended conditions of certification are adopted by the Commission and implemented by the project owner. The applicant has agreed to fund the creation of emission reduction credits by private funding to the Carl Moyer Fund, or through similar means, in sufficient quantity to fully offset all nonattainment pollutants and their precursors at a minimum ratio of 1:1.

Staff has assessed both the potential for localized impacts and regional impacts for the project's construction and operation, and as a product of this analysis staff has recommended mitigation and monitoring requirements that should provide adequate mitigation and monitoring sufficient to reduce the adverse construction and operating emission impacts to less than significant.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in AIR APPENDIX A. The Orange Grove Project, as a peaking project with an enforceable operating limitation less than 60% of capacity, is not subject to the requirements of SB1368 and the Emission Performance Standard. Staff recommends reporting of the GHG emissions as the Air Resources Board develops greenhouse gas regulations and/or trading markets. The project may be subject to additional reporting requirements and GHG reduction or trading requirements as these regulations become more fully developed and implemented.

Staff has provided comments on the District's Preliminary Determination of Compliance (PDOC) permit conditions that need to be resolved prior to completion of the Staff Assessment Addendum. Specific comments include inconsistencies with the applicant's supplied and stipulated emission rates and the emission rates in the PDOC and associated comments on the PDOC conditions. An addendum to this Staff Assessment will be prepared to address any changes needed to the emission rates and necessary revisions to the conditions of certification based on the conditions in the District's Final Determination of Compliance (FDOC).

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to the construction and operation of the proposed Orange Grove Project (OGP) by Orange Grove Energy, L.P. (applicant). The Site is located in north San Diego County, approximately 3.5 air miles northeast of Interstate (I) 15 on State Route (SR) 76, approximately 2.0 miles west of the community of Pala. The Site is located off of Pala Del Norte Road, a private road accessed from SR 76.

Criteria air pollutants are defined as those air contaminants for which the state and/or federal government has established an ambient air quality standard to protect public health. The criteria pollutants analyzed are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), CO, ozone (O_3), PM10, and PM2.5. In addition, VOC emissions are analyzed because they are precursors to both O_3 and particulate matter. Because NO_2 and SO_2 readily react in the atmosphere to form other oxides of nitrogen and sulfur respectively, the terms nitrogen oxides (NOx) and sulfur oxides (SOx) are also used when discussing these two pollutants.

In carrying out the analysis, the California Energy Commission staff evaluated the following major points:

- Whether OGP is likely to conform with applicable Federal, State and San Diego Air Pollution Control District (SDAPCD or District) air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- Whether OGP is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards (Title 20, California Code of Regulations, section 1742 (b)); and
- Whether the mitigation proposed for OGP is adequate to lessen the potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies pertain to the control of criteria pollutant emissions and mitigation of air quality impacts. Staff's analysis examines the project's compliance with these requirements.

Air Quality Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Part 52	Nonattainment New Source Review (NSR) requires a permit and requires Best Available Control Technology (BACT) and offsets. Permitting and enforcement delegated to SDAPCD. Prevention of Significant Deterioration (PSD) requires major sources to obtain permits for attainment pollutants. A major source for a simple-cycle combustion turbine is defined as any one pollutant exceeding 250 tons per year. Since the emissions from OGP would not exceed 250 tons per year, PSD does not apply.
40 CFR Part 60 Subpart KKKK	New Source Performance Standard (NSPS) for gas turbines: 15 parts per million (ppm) NOx at 15% O_2 and fuel sulfur limit of 0.060 lb SOx per million Btu heat input. BACT is more restrictive.
40 CFR Part 70	Title V: federal permit. Title V permit application is required within one year of start of operation. Permitting and enforcement delegated to SDAPCD.
40 CFR Part 72	Acid Rain Program. Requires permit and obtaining sulfur oxides credits. Permitting and enforcement delegated to SDAPCD.
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with Air Resource Board (ARB) approved Clean Air Plans.
HSC Section 41700	Restricts emissions that would cause nuisance or injury.
California Code of Regulations (CCR) Section 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits the types of fuels allowed, established maximum emission rates, establishes recordkeeping requirements.
Local – San Diego Air Pollution Control District (SDAPCD) Rule and Regulations	
Regulation II – Permits	This regulation sets forth the regulatory framework of the application for and issuance of construction and operation permits for new, altered, and existing equipment. Included in these requirements are the federally delegated requirements for New Source Review, Title V Permits, and the Acid Rain Program. Regulation II Rule 20.1 and 20.3 establishes the pre-construction review requirements for new, modified, or relocated facilities, in conformance with the federal New Source Review regulation to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the San Diego County is not unnecessarily restricted. This regulation establishes Best Available Control Technology (BACT) and emission offset requirements.

Applicable Law	Description
Regulation IV – Prohibitions	This regulation sets forth the restrictions for visible emissions, odor nuisance, various air emissions, and fuel contaminants. This regulation also specifies additional performance standards for stationary gas turbines and other internal combustion engines. However, for this project these provisions are less strict than the new source rule requirements of Regulation II.
Regulation X – Standards of Performance for New Stationary Sources	Regulation X incorporates provisions of 40 CFR Part 60, Chapter I, and is applicable to all new, modified, or reconstructed sources of air pollution. Sections of this federal regulation apply to stationary gas turbines (40 CFR Part 60 Subpart KKKK) as described above in the federal LORS description. These subparts establish limits of NO_2 and SO_2 emissions from the facility as well as monitoring and test method requirements. SDAPCD has not yet been delegated enforcement authority for this NSPS, but expects delegation later this year.
Regulation XI – National Emission Standards for Hazardous Air Pollutants	Regulation XI adopts federal standards for hazardous air pollutants (40 CFR Part 63) by reference. No such standards presently exist that would apply to the project.
Regulation XII – Toxic Air Contaminants – New Source Review	Regulation XII, Rule 1200, establishes the pre-construction review requirements for new, modified, or relocated sources of toxic air contaminant, including requirements for Toxics Best Available Control Technology (T-BACT) if the incremental project risk exceeds rule triggers.
Regulation XIV – Title V Operating Permits	Regulation XIV, Rule 1401 defines the permit application and issuance as well as compliance requirements associated with the Title V federal permit program. Any new source which qualifies as a Title V facility must obtain a Title V permit within 12 months of starting operation modification of that source. Regulation II, Rule 1412 defines the requirements for the Acid Rain Program, including the requirement for a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOx, NOx, and carbon dioxide (CO_2) emissions from the facility.

The District is currently working on several new rules, of which only one would directly impact the construction or operation of the proposed project. A fugitive dust rule, to be numbered Rule 55, is in the development process at the District. This rule may be promulgated before or during the proposed project’s construction, and may be considered by the Air Pollution Control Board for adoption before the end of 2008 (SDAPCD 2008b); however, District staff has indicated that the Energy Commission’s standard construction fugitive dust control measures are more stringent than the measures currently anticipated to be included in this future rule (Hamilton 2008).

SETTING

METEOROLOGICAL CONDITIONS

The climate of the San Diego Air Basin is controlled by a semi-permanent subtropical high-pressure system that is located off the Pacific Ocean. In the summer, this strong high-pressure system results in clear skies, high temperatures, and low humidity. Very little precipitation occurs during the summer months because storms are blocked by the high-pressure system. Beginning in the fall and continuing through the winter, the high pressure weakens and moves south, allowing storm systems to move through the area. Temperature, winds, and rainfall are more variable during these months, and stagnant conditions occur more frequently than during summer months. Weather patterns include periods of stormy weather with rain and gusty winds, clear weather that can occur after a storm, or persistent fog. The project site, as determined using nearby Pala, receives an average of approximately 14 inches of rain annually (WC 2008).

The applicant provided two sets of wind speed and wind direction data collected in the Gregory Canyon monitoring station and the Escondido monitoring station (APPENDIX 6.2-A-Meteorological Data Summaries). The prevailing annual wind direction from Gregory Canyon is from the west southwest with the average speed of 2.18 meters/second (m/s). The west southwest direction is particularly dominant during the second and third quarter of the year. The wind during the first and fourth quarter has two major prevailing wind directions, which are from the west southwest and the east northeast. The wind speeds are generally faster in the second and third quarter and slower in the first and fourth quarter. Since the Gregory Canyon is located only 1 mile southwest of the site, and its meteorological data are closest to the project site, these data are used to model the ambient incremental criteria pollutant contributions for the Project. The prevailing annual wind direction observed from Escondido station is from the west with the average speed of 1.70 m/s. The westerly direction is particularly dominant in the second and third quarter while the first and the fourth quarter have slightly different prevailing wind direction. The first quarter has two major prevailing wind directions, which are from the west and east northeast. During the fourth quarter of the year, the prevailing wind direction is from the east.

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability reflects the amount of atmospheric turbulence and mixing. In general, the less stable an atmosphere, the greater the turbulence, which results in more mixing and better dispersion. The mixing height, measured from the ground upward, is the height of the atmospheric layer in which convection and mechanical turbulence promote mixing. Good ventilation results from a high mixing height and at least moderate wind speeds with the mixing layer. In general, mixing is more limited at night and in the winter in San Diego when there is a higher potential for lower level inversion layers being present along with low surface winds. Low level inversions are often more prevalent in terrain protected valley locations such as in the San Luis Rey River valley.

EXISTING AIR QUALITY

The project is located within the jurisdiction of the San Diego Air Pollution Control District (District). The applicable federal and California ambient air quality standards (AAQS) are presented in **Air Quality Table 2**. As indicated in this table, the averaging times for the various air quality standards (the duration over which they are measured) range from one-hour to annual average. The standards are read as a mass fraction, in parts per million (ppm), or as a concentration, in milligrams or micrograms of pollutant per cubic meter of air (mg/m^3 or $\mu g/m^3$).

The U.S. Environmental Protection Agency (U.S. EPA), California Air Resource Board (ARB), and the local air district classify an area as attainment, unclassified, or nonattainment, depending on whether or not the monitored ambient air quality data show compliance, insufficient data is available, or non-compliance with the ambient air quality standards, respectively. The Orange Grove project site is located within the San Diego Air Basin (SDAB) and, as stated above, is under the jurisdiction of the San Diego Air Pollution Control District. This area is designated as nonattainment for both the federal and state ozone standards and the state PM10 and PM2.5 standards. **Air Quality Table 3** summarizes federal and state attainment status of criteria pollutants for the SDAB.

The project site is located in northern San Diego County, 3.5 miles northeast of I-15 on SR-76, approximately 2 miles west of Pala and located off of Pala Del Norte Road. The project site is located on land owned by San Diego Gas & Electric (SDG&E) that also contains an existing SDG&E storage area and the existing Pala Substation south southwest of the OGP project site boundary.

Air Quality Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.075 ppm (147 μg/m^3)	0.070 ppm (137 μg/m^3)
	1 Hour	—	0.09 ppm (180 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual Arithmetic Mean	0.053 ppm (100 μg/m^3)	0.03 ppm (57 μg/m^3)
	1 Hour	—	0.18 ppm (339 μg/m^3)
Sulfur Dioxide (SO_2)	Annual Arithmetic Mean	0.030 ppm (80 μg/m^3)	—
	24 Hour	0.14 ppm (365 μg/m^3)	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1300 μg/m^3)	—
	1 Hour	—	0.25 ppm (655 μg/m^3)
Respirable Particulate Matter (PM10)	Annual Arithmetic Mean	—	20 μg/m^3
	24 Hour	150 μg/m^3	50 μg/m^3
Fine Particulate Matter (PM2.5)	Annual Arithmetic Mean	15 μg/m^3	12 μg/m^3
	24 Hour	35 μg/m^3	—
Sulfates (SO_4)	24 Hour	—	25 μg/m^3
Lead	30 Day Average	—	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 μg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

Source: ARB 2008a.

Air Quality Table 3
Federal and State Attainment Status for the San Diego Air Basin

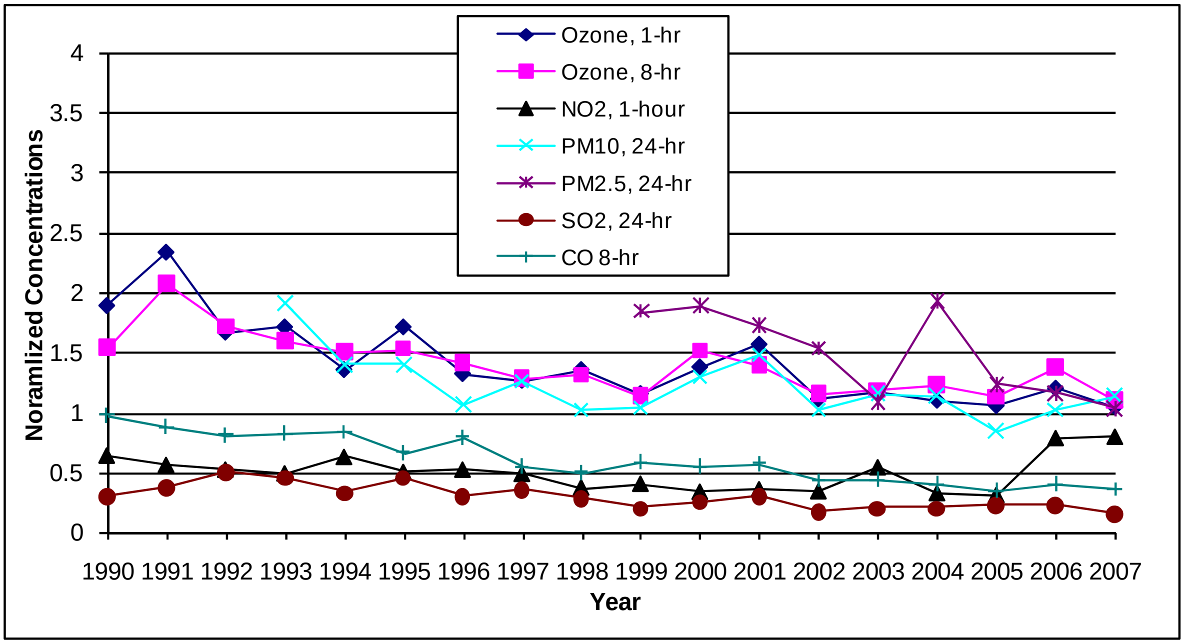
Pollutant	Attainment Status	
	Federal	State
Ozone	Nonattainment (8-hr)	Serious Nonattainment (1-hr)
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Attainment	Nonattainment
PM2.5	Attainment	Nonattainment

Source: ARB 2008b, U.S. EPA 2008.

The monitoring station closest to the proposed project site with a long-term record of all the criteria pollutants, except SO_2, is the Escondido – E Valley Parkway Station, located approximately 16 miles south of the project site. This station monitors ambient concentrations of ozone, NO_2, CO, PM10, and PM2.5. The San Diego 1110 Beardsley Street Station, approximately 45 miles south of the project site, is the closest station that has most recently monitored SO_2 concentrations; however, in the past SO_2 has been monitored closer to the project site (Escondido). To the extent that monitoring data from the Escondido and San Diego monitoring stations have been used to characterize conditions at the project site, this practice would generally overestimate existing pollutant levels at the OGP site because of the much lower population and level of development of the project area compared to the urban/suburban areas of Escondido and San Diego.

Air Quality Figure 1 summarizes the historical air quality data for the project location, recorded at Escondido - E Valley Parkway (1990-2007 for ozone, CO, NO_2; 1993-2007 for PM 10; 1999-2007 for PM2.5; 1990-1992 for SO_2), San Diego 12th Avenue (1993-2005 for SO_2), and San Diego 1110 Beardsley Street (2005-2007) air monitoring stations. In **Air Quality Figure 1**, the short term normalized concentrations are provided from 1990 to 2007. Normalized concentrations represent the ratio of the highest measured concentrations in a given year to the most-stringent applicable national or state ambient air quality standard. Therefore, normalized concentrations lower than one indicates that the measured concentrations were lower than the most-stringent ambient air quality standard.

Air Quality Figure 1
Normalized Maximum Short-Term Historical Air Pollutant Concentrations



Source: ARB 2008c, SDAPCD 2008a

A normalized concentration is the ratio of the highest measured concentration to the applicable most stringent air quality standard. For example, in 1999 the highest one-hour average ozone concentration measured at the Escondido-E Valley Parkway was 0.104 ppm. Since the most stringent ambient air quality standard is the state standard of 0.09ppm, the 1999 normalized concentration is 0.104/0.09=1.156

Following is a more in-depth discussion of ambient air quality conditions in the project area.

Ozone

In the presence of ultraviolet radiation, both nitrogen oxides (NOx) and volatile organic compounds (VOC) go through a number of complex chemical reactions to form ozone. **Air Quality Table 4** summarizes the most representative ambient ozone data collected from the Escondido E Valley Parkway monitoring station. The table includes the maximum one-hour and eight-hour ozone levels and the number of days above the state or national standards. Ozone formation is higher in spring and summer and lower in the winter. The SDAB was classified as an attainment area for the previous federal 1-hour ozone standard (no longer applicable) and is currently classified as a basic nonattainment area for the federal 8-hour ozone standard. The SDAB is also classified as a serious nonattainment area for the state 1-hour ozone standard.

Air Quality Table 4
Ozone Air Quality Summary, 1990-2007 (ppm)

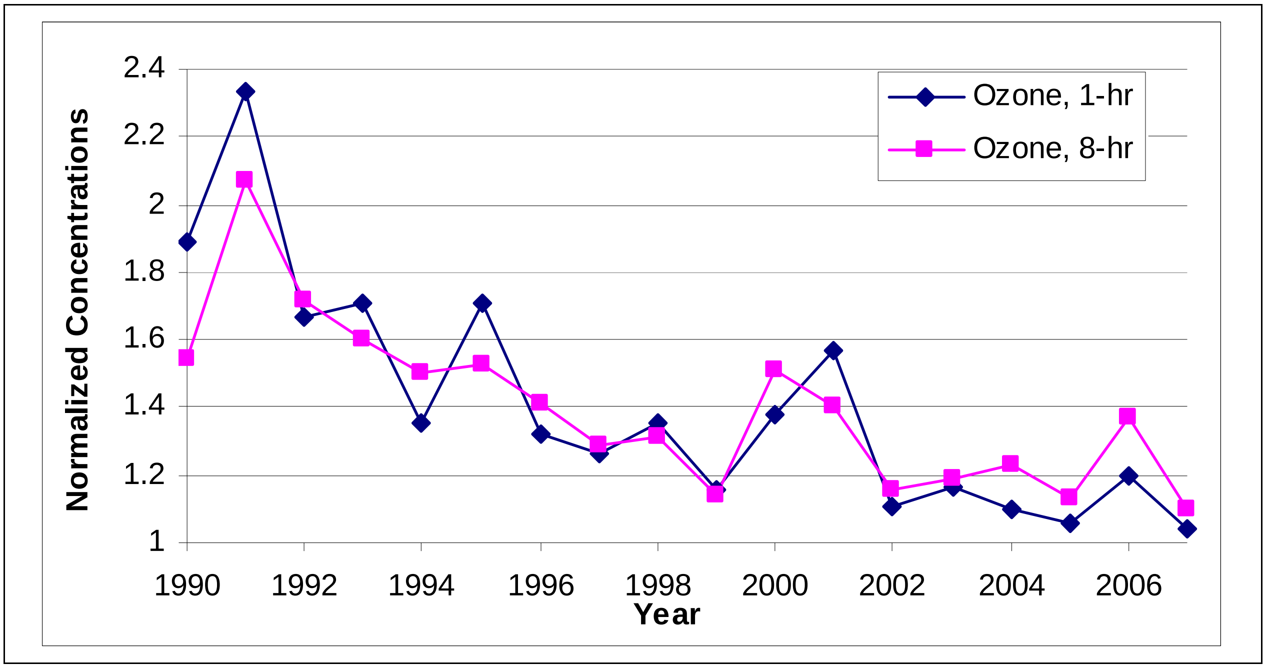
Year	Days Above CAAQS 1-Hr	Month of Max. 1-Hr Avg.	Max. 1-Hr Avg.	Days Above CAAQS 8-Hr	Month of Max. 8-Hr Avg.	Max. 8-Hr Avg.
1990	26	JUN	0.170	37	JUN	0.109
1991	27	OCT	0.210	48	OCT	0.145
1992	25	APR	0.150	48	APR	0.120
1993	16	SEP	0.154	37	SEP	0.113
1994	10	AUG	0.122	22	AUG	0.106
1995	12	JUL	0.154	24	JUL	0.108
1996	12	JUN	0.119	25	JUN	0.099
1997	5	OCT	0.114	15	JUL	0.090
1998	9	JUL	0.122	17	AUG	0.092
1999	1	AUG	0.104	4	APR	0.080
2000	6	SEP	0.124	13	SEP	0.106
2001	4	SEP	0.141	8	SEP	0.099
2002	2	SEP	0.100	3	SEP	0.082
2003	3	SEP	0.105	9	SEP	0.084
2004	2	APR	0.099	9	APR	0.087
2005	1	SEP	0.095	2	APR	0.080
2006	3	JUL	0.108	11	JUL	0.097
2007	0	AUG	0.094	5	SEP	0.078
California Ambient Air Quality Standard (CAAQS): 1-Hr, 0.09 ppm, 8-Hr, 0.070 ppm National Ambient Air Quality Standard (NAAQS): 8-Hr, 0.075 ppm						

Source: ARB 2008c

The yearly trends from 1990 to 2006 for the maximum one-hour and eight-hour ozone concentrations, referenced to the most stringent standard, and the number of days exceeding the California one-hour standard and the federal eight-hour standard for the Escondido-E Valley Parkway (1990-2006) monitoring station are shown in **Air Quality Figure 2** and **Figure 3**, respectively.

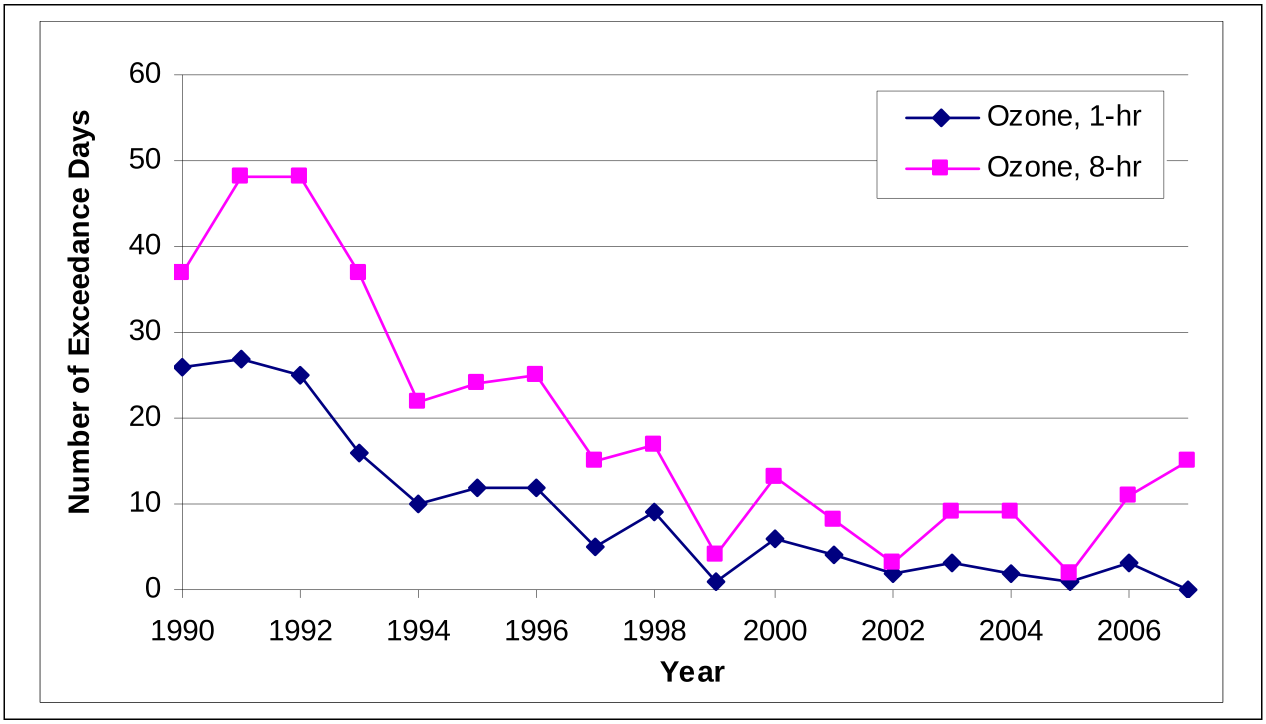
As these two figures show, the one-hour and eight-hour ozone concentrations and the number of exceedances were highest in 1991. There has been a trend of gradual improvements in ozone concentrations since 1990.

Air Quality Figure 2
Normalized Ozone Air Quality Maximum Concentrations



Source: ARB 2008c.

Air Quality Figure 3
Ozone – Number of Days Exceeding the Air Quality Standards



Source: ARB 2008c.

Respirable Particulate Matter (PM10)

The SDAB is classified as an attainment area for the federal PM10 standard and as a nonattainment area for the state PM10 standards. **Air Quality Table 5** summarizes the most representative ambient PM10 data collected from the Escondido E Valley Parkway monitoring station. As can be seen the monitoring station closest to the project area annually experiences a number of violations of the state 24-hour PM10 standard.

Air Quality Table 5
PM10 Air Quality Summary, 1993-2007 ($\mu g/m^3$)

Year	Days * Above Daily CAAQS	Month of Max. Daily Avg.	Max. Daily Avg.	Annual Arithmetic Mean
1993	30	OCT	96	31.8
1994	30	NOV	70	35.3
1995	--	DEC	70	--
1996	12	DEC	53	26.7
1997	19	OCT	63	28.8
1998	--	OCT	51	--
1999	0	DEC	52	29.7
2000	12	DEC	65	29.5
2001	13	JAN	74	30.6
2002	0	SEP	51	27
2003	31	DEC	58[a]	33
2004	6	JAN	57	27.3
2005	0	OCT	42	23.9
2006	6	DEC	51	24.2
2007	12	NOV	57[a]	24

California Ambient Air Quality Standard: 24-Hr, 50 $\mu g/m^3$; Annual Arithmetic, 20 $\mu g/m^3$
National Ambient Air Quality Standard: 24-Hr, 150 $\mu g/m^3$

* Days above the state standard (calculated and rounded): PM10 is monitored approximately once every six days. This value is a mathematical estimate of how many days the PM10 concentrations would have been greater than the level of the standard had each day been monitored.

[a] Excludes 2003 and 2007 firestorm events

Source: ARB 2008c, SDAPCD 2008a.

PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from turbines, and ammonia from NOx control equipment, given the right meteorological conditions, can form particulate matter in the form of nitrates (NO_3), sulfates (SO_4), and organic particles. These pollutants are known as secondary particulates, because they are not directly emitted, but are formed through complex chemical reactions in the atmosphere.

PM nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. The nitrate ion concentrations during the wintertime are a significant portion of the total PM10, and are likely even a higher contributor to particulate matter of less than 2.5 microns (PM2.5). The nitrate ion is only a portion of the PM nitrate, which can be in the form of ammonium nitrate (ammonium plus nitrate ions) and some as sodium nitrate. If the ammonium and the sodium ions associated with the nitrate ion are taken into consideration, PM nitrate contributions to the total PM are even more significant.

As shown in **Air Quality Table 5**, the highest PM10 concentrations are generally measured in the fall and winter when there are frequent low-level inversions. During the wintertime high PM10 episodes, the contribution of ground level releases to ambient PM10 concentrations is disproportionately high.

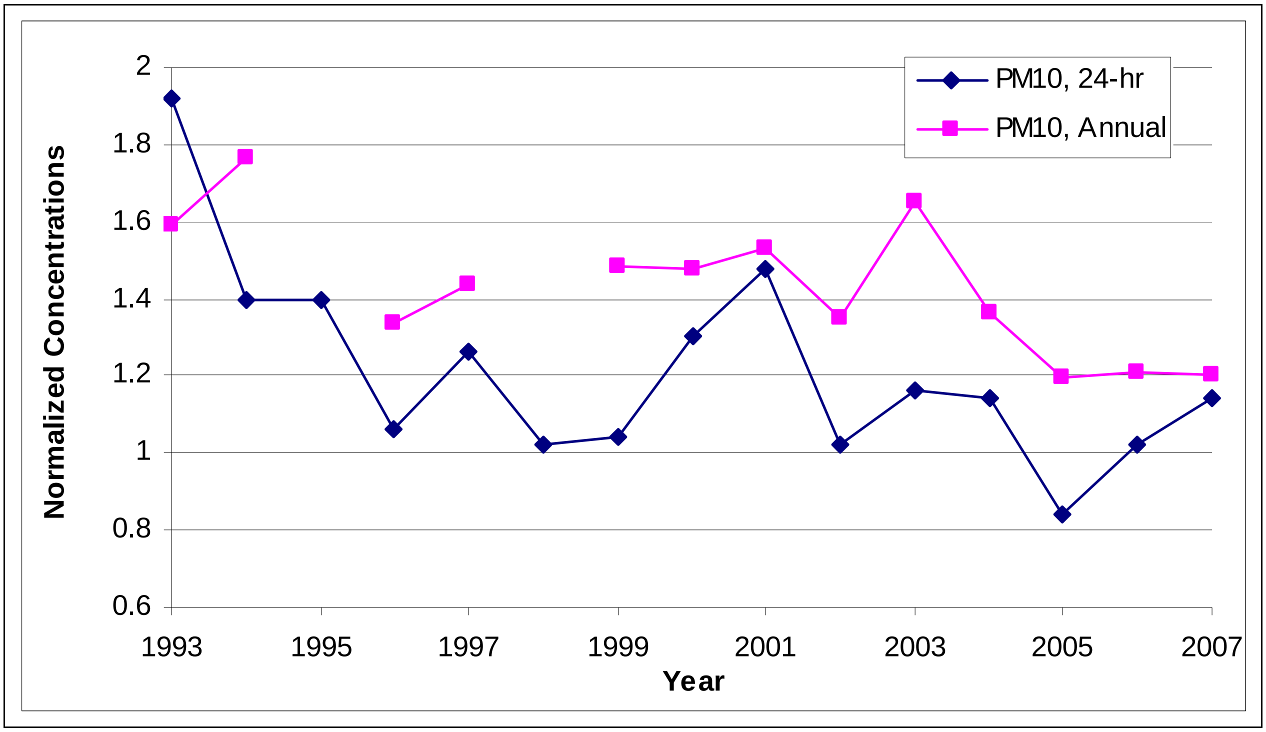
The 1993 to 2007 yearly trends for the maximum 24-hour PM10 and Annual Arithmetic Mean PM10, referenced to the most stringent standard, and the number of days exceeding the California 24-hour PM10 standard for the Escondido - E Valley Parkway (1993-2007) monitoring station is shown in **Air Quality Figure 4** and **Figure 5**, respectively.

As the two figures show, there is an overall gradual downward trend for PM10 concentrations and number of violations of the California 24-hour standard since 1993 however; there has been little progress since 1996.

Fine Particulate Matter (PM2.5)

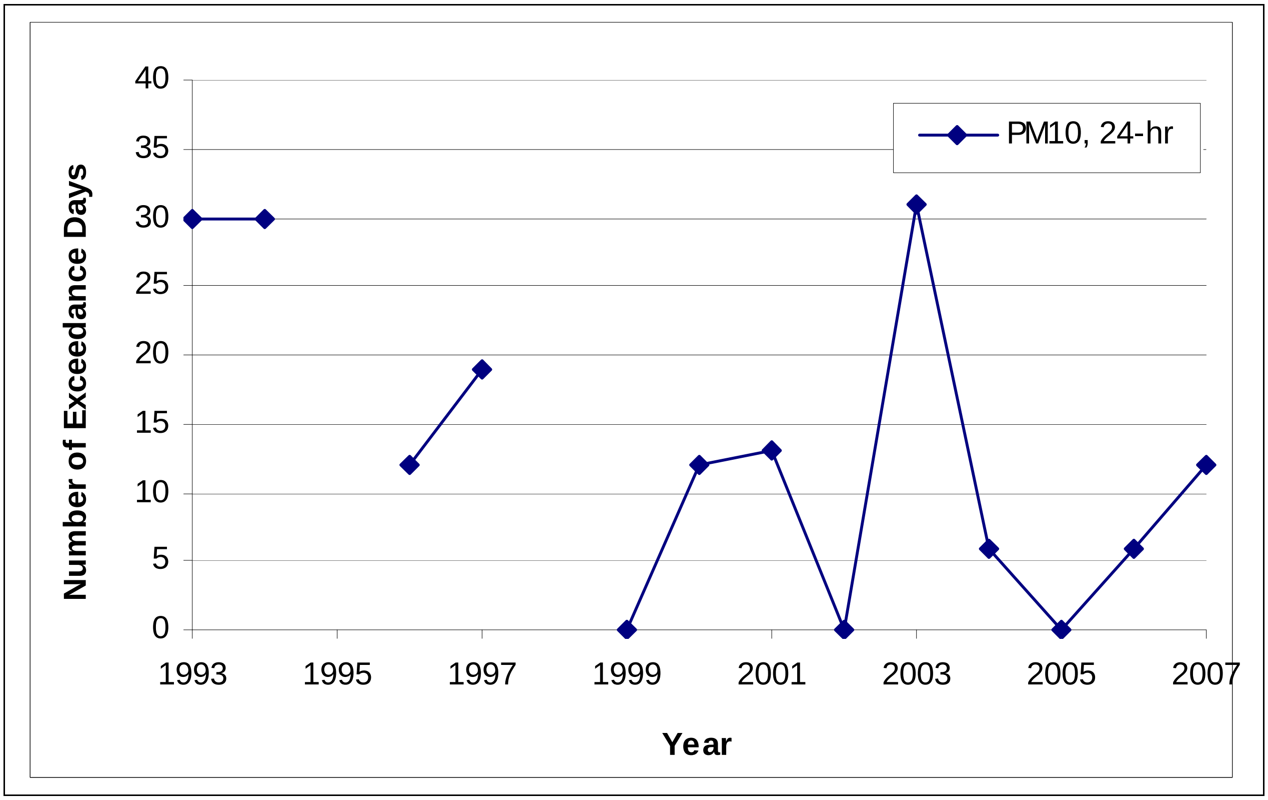
The SDAB is classified as nonattainment for the state respirable particulate matter (PM2.5) standard. The highest PM2.5 concentrations are generally measured in the winter. The relative contribution of wood-smoke particles to the PM2.5 concentrations may be even higher than its relative contribution to PM10 concentrations, considering that most of the wood-smoke particles are smaller than 2.5 microns.

Air Quality Figure 4
Normalized PM10 Air Quality Maximum Concentrations



Source: ARB 2008c, SDAPCD 2008a.

Air Quality Figure 5
PM10 24-Hour – Number of Days Exceeding the California Air Quality Standard



Source: ARB 2008c, SDAPCD 2008a.

As **Air Quality Table 6** indicates, the 24-hour (1-year average 98th percentile) and annual average PM2.5 concentration levels have been declining from 1999 to 2007.

Air Quality Table 6
PM2.5 Air Quality Summary, 1999-2007 ($\mu g/m^3$)

Year	National Maximum Daily	98th Percentile Maximum Daily	State Annual Average	National Annual Average
Escondido-E Valley Parkway				
1999	64.3	--	--	18
2000	65.9	--	--	15.8
2001	60	40.8	--	17.5
2002	53.6	--	--	16
2003	38[a]	33.9	14.2	14.2
2004	67.3	37.4	14.1	14.1
2005	43.1	--	12	12
2006	40.6	28.3	11.5	11.5
2007	36[a]	37.7	12	12

California Ambient Air Quality Standard: Annual Arithmetic Mean, 12 $\mu g/m^3$
National Ambient Air Quality Standard: 24-Hr Avg. Conc., 35 $\mu g/m^3$ (based on 98% of the daily concentrations, average over three years); Annual Arithmetic Mean, 15 $\mu g/m^3$

[a] Excludes 2003 and 2007 firestorm events

Source: ARB 2008c, SDAPCD 2008a.

The maximum daily PM2.5 concentrations shown in **Air Quality Table 6** all occurred in the late fall or winter (fourth and first quarters).

Carbon Monoxide (CO)

The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level in what is known as the stable boundary layer. These conditions occur frequently in the wintertime, late in the afternoon, persist during the night and may extend one or two hours after sunrise. Since mobile sources (motor vehicles) are the main cause of CO, ambient concentrations of CO are highly dependent on motor vehicle activity. In fact, the peak CO concentrations occur during the rush hour traffic in the mornings and afternoons. CO concentrations in San Diego County and the rest of the state have declined significantly due to two state-wide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phases I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to the decline in CO levels in the state. Today, the entire State of California is in attainment with the CO ambient air quality standards.

As **Air Quality Table 7** shows, the maximum one-hour and eight-hour CO concentrations in the project area are less than the California Ambient Air Quality Standards. CO is considered a local pollutant, as it is found in high concentrations only near the source of emission. Automobiles and other mobile sources are the principal sources of the CO emissions. High levels of CO emissions can also be generated from fireplaces and wood-burning stoves. According to the data recorded at the Escondido- E

Valley Parkway air monitoring station, there have been no violations of the California Ambient Air Quality Standards since 1990 for the one-hour and eight-hour CO standards. (see **Air Quality Figure 1 and Table 7**).

Air Quality Table 7
CO Air Quality Summary, 1990-2007 (ppm)

Year	Month of Max. 8-Hr Average	Maximum 1-Hr Average	Maximum 8-Hr Average
Escondido – E Valley Parkway			
1990	JAN	18	8.75
1991	DEC	12	7.88
1992	JAN	14	7.25
1993	NOV	11.4	7.38
1994	DEC	11	7.51
1995	NOV	9.9	5.95
1996	JAN	11.2	7.13
1997	NOV	9.3	4.91
1998	JAN	10.2	4.45
1999	DEC	9.9	5.26
2000	NOV	9.3	4.93
2001	JAN	8.5	5.11
2002	JAN	8.5	3.85
2003	FEB	8.9	3.9
2004	DEC	6.3	3.61
2005	JAN	5.9	3.1
2006	DEC	5.7	3.61
2007	DEC	5.2	3.19
California Ambient Air Quality Standard: 1-Hr, 20 ppm; 8-Hr, 9.0 ppm National Ambient Air Quality Standard: 1-Hr, 35 ppm; 8-Hr, 9 ppm			

Source: ARB 2006a, ARB2008c, SDAPCD 2008a.

Nitrogen Dioxide (NO_2)

As shown in **AIR QUALITY Table 8,** the maximum one-hour and annual concentrations of NO_2 at the Escondido - E Valley Parkway monitoring station are lower than the California and National Ambient Air Quality Standards.

Approximately 75-90% of the NOx emitted from combustion sources is NO, while the balance is NO_2. NO is oxidized in the atmosphere to NO_2, but some level of photochemical activity is needed for this conversion. This is why the highest concentrations of NO_2 generally occur during the fall and not in the winter, when atmospheric conditions favor the trapping of ground level releases, but lack significant photochemical activity (less sunlight). In the summer, the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) generally disperse pollutants, preventing the accumulation of NO_2

to levels approaching the California one-hour ambient air quality standard. The formation of NO_2 in the summer, in the presence of ozone, is according to the following reaction:

$$NO + O_3 \rightarrow NO_2 + O_2$$

In urban areas, ozone concentration levels are typically high. These levels drop substantially at night as the above reaction takes place between ozone and NO. This reaction explains why, in urban areas, ozone concentrations at ground level drop, while aloft and in downwind rural areas (without sources of fresh NOx emissions) ozone concentrations can remain relatively high.

Air Quality Table 8
NO_2 Air Quality Summary, 1996-2007 (ppm)

Year	Month of Max. 1-Hr Average	Maximum 1-Hr Average	Maximum Annual Average
Escondido- E Valley Parkway			
1990	OCT	0.16	0.029
1991	FEB	0.14	0.028
1992	JAN	0.13	0.026
1993	SEP	0.122	0.022
1994	JAN	0.157	0.024
1995	NOV	0.125	0.026
1996	NOV	0.13	0.020
1997	OCT	0.121	0.021
1998	OCT	0.092	0.018
1999	MAR	0.1	0.023
2000	NOV	0.083	0.021
2001	NOV	0.088	0.020
2002	FEB	0.084	0.021
2003	OCT	0.135	0.020
2004	OCT	0.08	0.018
2005	OCT	0.076	0.016
2006	NOV	0.071	0.017
2007	NOV	0.072	0.016
California 1-Hr Ambient Air Quality Standard: 0.18 ppm California Annual Arithmetic Mean Ambient Air Quality Standard: 0.030 ppm			

Source: ARB 2008c, SDAPCD 2008a.

Sulfur Dioxide (SO_2)

Sulfur dioxide is typically emitted as a result of the combustion of a fuel containing sulfur. Fuels, such as natural gas, contain very little sulfur and consequently have very low SO_2 emissions when combusted. By contrast, fuels high in sulfur content, such as coal, emit very large amounts of SO_2 when combusted.

Sources of SO_2 emissions within the SDAB come from every economic sector and include a wide variety of fuels: gaseous, liquid and solid. The SDAB is designated attainment for all the SO_2 state and federal ambient air quality standards. **Air Quality Table 9** shows the historic one-hour, 24-hour and annual average SO_2 concentrations collected from the Escondido – E Valley Parkway and San Diego 12 Avenue monitoring stations. As **Air Quality Table 9** shows, concentrations of SO_2 are far below the state and federal SO_2 ambient air quality standards.

Air Quality Table 9
SO_2 Air Quality Summary, 1990-2007 (ppm)

Year	Maximum 1-Hr Avg.	Month of Max. 24-Hr Avg.	Maximum 24-Hr Avg.	Annual Average
Escondido- E Valley Parkway				
1990	0.030	DEC	0.012	0.002
1991	0.070	FEB	0.015	0.003
1992	--	JAN	0.013	0.004
San Diego – 12 Avenue				
1993	0.047	JAN	0.018	0.003
1994	0.069	JUN	0.013	0.003
1995	0.063	AUG	0.018	0.003
1996	0.048	APR	0.012	0.003
1997	0.052	MAY	0.014	0.003
1998	0.04	JUL	0.011	0.003
1999	0.039	AUG	0.008	0.002
2000	0.038	SEP	0.010	0.004
2001	0.052	AUG	0.012	0.003
2002	0.028	SEP	0.007	0.003
2003	0.036	JAN	0.008	0.004
2004	0.042	SEP	0.008	0.004
San Diego – 1110 Beardsley Street				
2005	0.036	SEP	0.005	0.003
2006	0.034	FEB	0.009	0.004
2007	0.018	OCT	0.006	0.003
California Ambient Air Quality Standard: 1-Hr, 0.25 ppm; 24-Hr, 0.04 ppm National Ambient Air Quality Standard: 3-Hr, 0.5 ppm; 24-Hr, 0.14 ppm; Annual, 0.030 ppm				

Source: ARB 2006a, ARB 2008c, SDAPCD 2008a.

Visibility

Visibility in the region of the project site depends upon the area's natural relative humidity and the intensity of both particulate and gaseous pollution in the atmosphere. The most straightforward characterization of visibility is probably the visual range (the greatest distance that a large dark object can be seen). However, in order to characterize visibility over a range of distances, it is more common to analyze the changes in visibility in terms of the change in light-extinction that occurs over each additional kilometer of distance (1/km). In the case of a greater light-extinction, the visual range would decrease.

The SDAB is currently designated as unclassified for visibility reducing particles.

Summary

In summary, staff recommends the background ambient air concentrations in **Air Quality Table 10** for use in the modeling and impacts analysis. The maximum criteria pollutant concentrations from the past three years of available data collected at the monitoring stations within San Diego County are used to determine the recommended background values. The use of these recommended three-year maximum concentrations as background provides for a conservative ambient air quality analysis.

Air Quality Table 10
Staff Recommended Background Concentrations (µg/m^3)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour	143.1	339	42%
	Annual	32.3	57	57%
PM10	24 hour	57	50	114%
	Annual	24.2	20	121%
PM2.5	24 hour	37.7	35	108%
	Annual	12	12	100%
CO	1 hour	6,785	23,000	30%
	8 hour	4,011	10,000	40%
SO_2	1 hour	94.3	655	14%
	3 hour [a]	84.9	1,300	7%
	24 hour	23.6	105	23%
	Annual	10.7	80	13%

Source: ARB 2008c, SDAPCD 2008a and Energy Commission Staff Analysis
[a] The 3 hour background SO_2 concentration is assumed to be 90% of the 1 hour background.

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with similar characteristics; however no monitoring stations in similar rural areas are located near the project site. Monitoring stations located within larger urban areas (Escondido- E Valley Parkway and San Diego) provide conservative estimates for background concentrations. For all pollutants, except for SO_2, the highest monitored values from the Escondido- E Valley Parkway monitoring station were used to determine the background concentrations. For SO_2, the monitored concentrations from the 1110 Beardsley Street monitoring station in San Diego were used to determine the background concentrations.

The background concentrations for PM10 and PM2.5 are at or above the most restrictive existing ambient air quality standards, while the background concentrations for the other pollutants are all well below the most restrictive existing ambient air quality standards.

The pollutant modeling analysis was limited to the pollutants listed above in **Air Quality Table 10**; therefore, recommended background concentrations were not determined for the other criteria pollutants (ozone, lead, visibility, etc.)

PROJECT DESCRIPTION AND EMISSIONS

Orange Grove Energy, L.P. (Orange Grove Energy) has proposed the Orange Grove Project (the “Project”) to develop, build, own, and operate a 96 megawatt (MW) simple cycle power station. This project is being developed in response to a San Diego Gas & Energy (SDG&E) Request for Offers for new generating capacity to support reliability. The station would be on an 8.5-acre site in a rural area of northern San Diego County, California. The site is located on disturbed lands formerly used as a citrus grove, but the grove has not been maintained in at least 5 years. The existing SDG&E Pala substation is located on a continuous SDG&E parcel south of the site.

Orange Grove Energy would be responsible for construction of the power plant, the electric transmission line interconnection between the power plant and the substation boundary, and the gas pipeline from a tie-in at an existing SDG&E gas transmission main to the plant. Orange Grove Energy would operate the plant, which would employ up to 9 full-time onsite staff. Natural gas fuel would be supplied by SDG&E, and electric power generated would be supplied to SDG&E under a tolling agreement.

The project is designed as a peaking facility to supply electric power locally, primarily during times of high demand, which generally occur during daylight hours, and most frequently during the summer months. While being permitted for a total of 6,400 turbine hours of operation with 500 total starts annually, the facility is actually expected to operate less than 2,000 turbine hours to meet the peaking electricity demand. Additionally the plant would be limited to 6 total starts for both turbines each day.

CONSTRUCTION

Construction of the Orange Grove project would consist of the following: 1) clearing of agricultural vegetation; grading; hauling and laydown of equipment, materials, and supplies; facility construction; and testing; 2) the electric transmission line interconnection to the Pala substation; 3) gas pipe line construction. The construction period is expected to last approximately 6 months beginning in April 2009.

Combustion emissions during the construction of the project result from exhaust sources, including but not limited to diesel construction equipment used for site preparation, water trucks used to control dust emissions, cranes, diesel-powered welding machines, electric generators, air compressors, water pumps, diesel trucks used for deliveries, and automobiles used by workers to commute to and from the construction site.

Emissions of fugitive particulate matter (PM10 and PM2.5) result from grading and excavating disturbed areas, earthmoving operations and unpaved roadway during Site and pipeline construction. In addition to the pipeline construction, minor improvements would be made by Orange Grove Energy to the fresh and reclaim water supply pickup stations. Since the minimal improvements at the water pickup stations are minor and remote from the project site, they are not expected to result in significant air emissions.

Applicant estimates for the highest emissions during construction, which occur during initial site grading, are provided in **Air Quality Table 11**.

Air Quality Table 11
Summary of Onsite Construction Maximum Daily Emissions, lbs/day

Activity	NO_x	CO	VOC	SO_x	PM10	PM2.5
Equipment Combustion Emissions	132.82	59.65	14.27	0.11	5.80	5.34
Earth Moving Fugitive Dust	--	--	--	--	12.09	4.02
Material Handling Fugitive Dust	--	--	--	--	1.03	0.16
Unpaved Roadway Fugitive Dust	--	--	--	--	18.67	1.87
Total Maximum Daily Emissions	132.82	59.65	14.27	0.11	37.59	11.39

Source: OGE 2008a, as corrected and augmented by Energy Commission Staff.

The maximum daily emissions shown above were used for modeling maximum short-term construction emission air quality impacts.

The total emissions during construction, including onsite and offsite emissions are summarized in **Air Quality Table 12**.

Air Quality Table 12
Summary of Total Construction Emissions, tons

Activity	NO_x	CO	VOC	SO_x	PM10	PM2.5
Onsite						
Site Preparation/Grading	1.14	0.55	0.14	0.001	0.06	0.05
Main Site Construction	2.02	1.16	0.55	0.003	0.15	0.14
Fugitive Dust	---	---	---	---	0.25	0.06
Offsite						
Gas Line Construction	0.58	0.36	0.13	0.001	0.05	0.04
Worker and Delivery Trucks	0.49	2.89	0.31	0.000	0.04	0.03
Paved Road Fugitive Dust	---	---	---	---	0.27	0.05
Total Emissions	4.23	4.96	1.13	0.005	0.80	0.37

Source: OGE 2008a, as amended by Energy Commission Staff.

The onsite emissions shown above were used for modeling the annual construction emission air quality impacts.

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time between the completion of construction and the reliable production of electricity for sale on the market. For most power plants, normal operating emission limits usually do not apply during the initial commissioning activities.

Commissioning activities, as stipulated by the applicant, would occur only from 7 am to 7 pm for this project. Commissioning activities for the project CTGs are expected to last approximately 60 hours for each turbine. However, to account for potentially longer testing requirements, 200 hours of commissioning for each turbine would be provisioned in the permit. Commissioning would consist of the following test periods.

1. First fire of the unit, where each unit is operated on fuel at speeds ranging from minimum idle to full speed at no load and not tied to the grid. Correct electrical phase rotation is established and systems are checked out and tunes. (e.g. fuel gas compressors and the gas turbine fuel system). One 12-hour day per unit.

2. Synchronization, where the unit is tied to the grid and operated at low load (<15 MW with no water injection and SCR operation). Controls are tuned during this phase to establish reliable starting and stopping of the unit. Two 12-hour days per unit.

3. Low-load to full-load operation (approximately 1.5 MW to full-load, no SCR operation). Water injection and watering schedule are established during this phase to establish the desired gas turbine emissions profile. The gas turbine and generator excitation system controls are tuned to provide desired response. One 6-hour day per unit.

4. Low load to full-load operation (>15 MW to full-load), with water injection and SCR in operation. The SCR is commissioned and tuned. One 6-hour day per unit.

5. Power augmentation equipment (SPRINT and inlet chilling systems) are commissioned and tuned. SCR is re-tuned if necessary to account for power augmentation equipment. One 12-hour day per unit.

Only one unit would be commissioned at a time until both units can operate with fully-functioning emission control (SCR and oxidation catalyst) systems. This would minimize the maximum short term emissions potential during initial commissioning. **Air Quality Table 13** presents the applicant's estimated short-term emissions for each of the commissioning activities.

Air Quality Table 13
Summary of Maximum Short-Term Commissioning Emissions, lbs/hr

Commissioning Activity	Hours per Turbine		Emission Rate (lbs/hr)				
	Planned	Permitted	NO_x	CO	VOC	SO_x	PM10/PM2.5
First Fire	12	40	30.10	5.44	0.36	0.29	1.20
Synchronization	24	80	30.10	5.44	0.36	0.29	1.20
Low Load to Full Load, no SCR	6	20	20.61	12.56	0.58	0.48	1.66
Low Load to Full Load, SCR	6	20	2.06	4.40	0.58	0.48	1.66
Full Load with Sprint	12	40	4.35	15.37	1.21	1.00	3.00

Source: OGE 2008a.

While the maximum expected short-term emission rates are shown above, the absolute peak short-term emission rate for NOx and CO modeled was higher than the values listed above at 50 lbs/hour and 43.9 lbs/hour, respectively. The commissioning 1-hour emission limits are based on these absolute peak values.

Air Quality Table 14 presents the applicant's estimated total initial commissioning emissions for the Orange Grove gas turbines. It is important to note that commissioning emissions are worst-case, one-time emissions that would occur within a short 4 week window and only one turbine at a time would be operated without fully functioning emission controls during initial commissioning.

Air Quality Table 14
Summary of Maximum Commissioning Emissions, tons

Activity	NO_x	CO	VOC	SO_x	PM10/PM2.5
Planned (Each Turbine)	0.635	0.24	0.015	0.015	0.05
Planned (Total both Turbines)	1.27	0.48	0.03	0.03	0.10
Permitted (Total both Turbines)	4.24	1.61	0.11	0.09	0.33

Source: OGE 2008a.

OPERATIONAL PHASE

Equipment Description

The equipment for the proposed Orange Grove project would include the following major components (OGE 2008a):

- Two General Electric LM6000 PC SPRINT combustion turbine generators (CTGs) with SPRINT Power Boost System, each rated at approximately 50 MW;
- The CTGs would each be equipped with water injection to the combustors for reducing production of NOx, a selective catalytic reduction (SCR) system with 19% aqueous ammonia injection to further reduce NOx emissions, and an oxidation catalyst to reduce CO emissions;
- Inlet air filter system;
- Cooling tower consists of three Baltimore Aircoil Company Model 31132C cells equipped with drift eliminators;
- Black start engine, Cummins Model GTA38-G2 or equivalent natural gas fired engine producing 965 brake horsepower (bhp);
- Fire pump engine, Cummins Model CFP11E-F10 or equivalent diesel fired engine producing 373 bhp;
- Two exhaust stacks from the two CTGs (diameter of 12.5-feet and height of 80-feet);
- Two Emissions Control Module systems for control of NO_x and CO including tempering air fans and dilution air blowers;
- A continuous emission monitoring (CEM) system installed on each stack would record concentrations of NOx, CO, CO_2, and oxygen in the flue gas;
- Raw water storage tank (535,000 gallons);
- One demineralized water storage tanks (100,000 gallons); and
- One 10,000 gallon aqueous ammonia tanks.

Orange Grove Energy would purchase new single-trailer semi trucks for hauling the operations water supply to the site. The trucks would be fueled with ultra low-sulfur diesel fuel and would have a capacity of approximately 6,500 gallons. The water supply is planned to be obtained using both a reclaim water pickup station and a fresh water pickup station. Water hauling would entail approximately one truck per hour for fresh water and one truck per hour for reclaim water for times that the plant is operating. Based on expected use of the plant, water hauling is expected to typically occur about

60 days per year. The plant would typically run the most during summer months and onsite storage would provide substantial storage capacity for peak operating days.

Facility Operation

The Orange Grove plant is proposed to provide up to 6,400 hours (3,200 per turbine) of annual operation to SDG&E. The facility is capable of operating continually (24 hours per day, seven days per week) if called and needed to support the electric system but it is not anticipated to be dispatched at this level. The actual hours that the plant would run annually for each mode of operation are expected to be less than 2,000 turbine hours to meet the peaking electricity demand.

The proposed startup and operating limits for the project are outlined as follows:

- One-time startup and commissioning - 400 hours total:
  - 240 hours of uncontrolled emissions for startup and commissioning of each CTG.
  - 40 hours per unit with emissions controlled at the turbine only (approximately 25 ppmvd NO_x and 25 ppmvd CO, both corrected to 15% O_2), for startup and commissioning of the SCR and oxidation catalyst systems.
- Annual operation (two turbines combined) – 6,400 hours total:
  - 5,960 turbine hours of fully controlled emissions.
  - 40 turbine hours of emissions controlled at the CTGs only for annual maintenance and testing.
  - 500 combined startups composed of 10 minutes of uncontrolled emissions (water injected CTGs only; no additional reduction via catalyst) and 30 minutes of linearly decreasing controlled emissions as the CO and NO_x catalyst become effective.
  - 500 combined shutdowns composed of 8 minutes of uncontrolled emissions (water-injected CTGs only).
- Emergency equipment testing emissions:
  - Diesel-driven fire pump tested weekly for 30 minutes.
  - Black-start generator tested monthly for 30 minutes.
  - Each CTG, to the extent not operated in the previous 2 weeks, would be started approximately once per month and operated for 1 hour.

Emission Controls

The exclusive use of pipeline-quality natural gas, a relatively clean-burning fuel, would limit the formation of VOC, PM10, and SO_2 emissions. Natural gas contains very little noncombustible gas or solid residues and a small amount of reduced sulfur compounds, including mercaptan. Water injection to the CTG combustors in conjunction with selective catalytic reduction (SCR) would be used to control NOx concentrations in the exhaust gas. Post-combustion NOx control would be provided using a selective catalytic reduction (SCR) system. The SCR system would use aqueous ammonia to further reduce NOx emissions to 2.5 parts per million by volume, dry (ppmvd) adjusted to 15% oxygen from the gas turbines/SCR systems. Ammonia slip would be limited to 5 ppmvd at 15% oxygen on a dry basis. An oxidizing catalytic converter would be used to reduce the CO concentration in the exhaust gas emitted to the atmosphere to 6 ppmvd adjusted to 15% oxygen from the CTGs. Particulate emissions would be controlled using natural gas as the sole fuel for the CTG and inlet air filtration (OGE 2008a).

Two 80-foot-tall, 12.5-foot diameter stacks would release the CTG exhaust gas into the atmosphere. A continuous emission monitoring (CEM) system would be installed on the CTG stack to monitor fuel gas flow rate, NO_x and CO concentration levels, and percentage of oxygen in the flue gas to assure adherence with the proposed emission limits. The CEM system would generate reports of emissions data in accordance with permit requirements and send alarm signals to the plant's control room when the level of emissions approaches or exceeds pre-selected limits.

Project Operating Emissions

The majority of the criteria pollutant emissions would be generated from the operation of the two CTGs. The maximum controlled steady state operating emissions when running at full load for the CTGs is summarized in **Air Quality Table 15.**

Air Quality Table 15
Maximum Steady State Pollutant Emission Rates, lb/hr

Pollutant	ppmvd @ 15% O_2	Each CTG	Two CTGs
NOx	2.5	4.30	8.60
CO	6.0	6.12	12.24
VOC	2.0	1.25	2.50
PM10/PM2.5	---	3.00	6.00
SO_2 [a]	---	1.00	2.00
NH_3	5.0	3.01	6.02

Source: OGE 2008a, SDAPCD 2008c.
[a] SO_2 emissions are based on regulated maximum SDG&E natural gas sulfur content of 0.75 grains/100 dry standard cubic feet.

Air Quality Table 16 contains a summary of maximum hourly emissions per turbine resulting from the startup, shutdown, and uncontrolled steady-state operations. Startup period reflects 10 minutes of startup operation, 30 minutes of warm up, and 20 minutes of controlled steady state. Shutdown period reflects 52 minutes of controlled steady state and 8 minutes of shutdown operation. Startup/shutdown period reflects 10 minutes of startup, 30 minutes of controlled steady state, and 8 minutes of shutdown. Uncontrolled steady-state operations occur when the emission controls are not functioning during certain applicant requested maintenance operations. Operating load is set to be 100% for all cases to estimate the maximum emissions.

Air Quality Table 16
Maximum Short-Term Event Emissions

Short-Term Event	NO_x	CO	VOC	SO_x	PM10/PM2.5
Startup – 10 minutes (lbs)	3.00	5.60	1.10	0.14	--
Warm-up – 30 minutes (lbs)	10.93	7.50	1.11	0.41	--
Steady State Controlled - 20 minutes (lbs)	1.43	2.04	0.42	0.33	--
Startup Event Total (lbs/hr)	15.36	15.14	2.63	0.88	3.00
Steady State Controlled – 52 minutes (lbs)	3.73	5.31	1.08	0.87	--
Shutdown – 8 minutes (lbs)	2.20	3.70	0.60	0.11	--
Shutdown Event Total (lbs/hr)	5.93	9.01	1.68	0.98	3.00
Startup/Shutdown [a] (lbs/hr)	16.13	16.8	2.81	0.66	3.00
Uncontrolled Steady-State[b] (lbs/hr)	43.00	18.37	1.25	1.00	3.00

Source: OGE 2008a, SDAPCD 2008c.
[a] Assumes startup and shutdown occur in the same hour.
[b] This activity, requested by the applicant does not appear to be allowed by the District in the PDOC.

Air Quality Tables 17, 18, and 19 summarize the maximum estimated hourly, daily, and annual criteria pollutant emissions for the OGP based on maximum permitted operation[1]. To assess maximum hourly, daily, and annual emissions, the following assumptions were made for each case:

Maximum Hourly Emissions:

- Two turbines undergo startup operation for 10 minutes.
- Two turbines undergo warm-up operation for 30 minutes.
- Two turbines operate at steady state for 20 minutes.
- The fire water pump engine is tested for one-half hour.
- The black-start engine is tested for one-half hour.
- The cooling tower operates for a full hour at maximum water recirculation rate (8,500 gallons/minute), has a mist eliminator that reduces drift to 0.001% of the recirculation rate and the maximum water total dissolved solids content would be 4,594 ppm.

Maximum Daily Emissions:

- Two turbines undergo three startups per day.
- Two turbines undergo three shutdowns per day.
- Two turbines operate at controlled steady state for the balance of the day.
- The fire water pump engine is tested for one-half hour per day.
- The black-start engine is tested for one-half hour per day.
- The cooling tower operates at maximum water recirculation rate for 24 hours.

Permitted Maximum Annual Emissions:

[1] The maximum ammonia emissions are based on 6.02 lbs/hour for both turbines, where maximum daily is based on 24 hours/day (144.48 lbs/day) and maximum annual is based on 3,200 hours/year (9.63 tons/year).

- Two turbines undergo 250 startups/warm-ups per year (166.7 hours total).
- Two turbines undergo 250 shutdowns per year (33.3 hours total).
- Two turbines operate at controlled steady state for 3,000 hours.
- The fire water pump engine is tested for 52 hours per year.
- The black-start engine is tested for 7 hours per year.
- The cooling tower operates at maximum water recirculation rate for 3200 hours.

Air Quality Table 17
Summary of Maximum Hourly Operational Emissions[a], lbs/hr

	NO_x	CO	VOC	SO_x	PM10/PM2.5
Turbines	30.73	30.28	5.25	2.00	6.00
Black-Start Engine	1.39	1.85	0.31	0.008	0.04
Fire Water Pump Engine	1.58	0.31	0.0003	0.01	0.04
Chiller Cooling Tower	--	--	--	--	0.20
Water Trucks	0.64	0.14	0.03	0.002	0.07/0.03
Maximum Facility Hourly	34.34	32.58	5.59	1.79	6.49/6.45

Source: OGE 2008a, SDAPCD 2008c
[a] Assumes startup and shutdown occur in the same hour.

Air Quality Table 18
Summary of Maximum Daily Operational Emissions, lbs/day

	NO_x	CO	VOC	SO_x	PM10/PM2.5
Turbines	282.5	365.3	70.86	47.2	144
Black-Start Engine	1.39	1.85	0.31	0.008	0.04
Fire Water Pump Engine	1.58	0.31	0.0003	0.001	0.04
Chiller Cooling Tower	--	--	--	--	4.69
Water Trucks	15.30	3.31	0.76	0.05	1.75/0.71
Maximum Facility Daily	300.77	370.77	71.93	47.26	150.5/149.5

Source: OGE 2008a, SDAPCD 2008c

Air Quality Table 19
Summary of Maximum Annual Operational Emissions, ton/year

	NO_x	CO	VOC	SO_x	PM10/PM2.5
Turbines	16.93	22.56	4.45	3.17	9.60
Black-Start Engine	0.001	0.013	0.002	0.00006	0.0003
Fire-Pump Engine	0.041	0.008	0.00001	0.00003	0.001
Chiller Cooling Tower	--	--	--	--	0.313
Water Trucks	1.02	0.22	0.051	0.003	0.12/0.05
Maximum Facility Annual (ton/year)	17.99	22.80	4.50	3.17	10.03/9.96

Source: OGE 2008a, SDAPCD 2008c

The actual maximum annual operation is expected to be significantly less than that being permitted through SDAPCD. The applicant also acknowledges this fact and has provided an expected maximum operating basis to be used for California Environmental Quality Act (CEQA) mitigation. This expected maximum basis assumes maximum annual operations of 1,200 hours per year (TRC 2008f).

Air Quality Table 20 summarizes the applicant's expected estimate for the maximum annual emissions for the OGP[2]. The following assumptions were used by the applicant in determining the expected maximum annual emissions as follows:

Expected Maximum Annual Emissions:

- Two turbines undergo 100 startups/warm-ups (66.67 hours total).
- Two turbines undergo 100 shutdowns (13.33 hours total).
- Two turbines operate at controlled steady state for 1,120 hours.
- Water truck trips are reduced correspondingly with reduced turbine operations.
- Cooling tower operates for 1,200 hours.
- Emergency Engines operate the same as under maximum permit basis.

Air Quality Table 20
Applicant Estimated Maximum Annual Emissions (CEQA Mitigation Basis)[3], tons

	NO_x	VOC	SO_x	PM10
Turbines	6.43	1.68	0.40[b]	3.60
Black-Start Engine	0.01	0.00214	0.00006	0.00028
Fire Water Pump Engine	0.04	0.00001	0.00002	0.00097
Chiller Cooling Tower	--	--	--	0.12
Water Trucks	0.36	0.019	0.001	0.044
Maximum Facility Annually (ton/year)	6.86	1.70	0.40	3.76

Source: TRC 2008f
[a] Revised by staff assuming a reasonable long-term natural gas sulfur content of 0.25 grains/100 scf.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses three kinds of impacts: construction, operation, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time, together with other closely related past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and 15355.) Additionally, cumulative impacts are assessed in terms of conformance with the District's attainment or maintenance plans.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff used two main significance criteria in evaluating this project. First, all project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, PM10

[2] The applicant originally proposed a 1,000 total hour basis, but is willing to stipulate to the same operating hours as recommended by staff for the Chula Vista Energy Upgrade Project's CEQA mitigation basis (CEC 2008o).

[3] CEQA mitigation for PM is based on PM10 emissions and no mitigation is recommended for CO since it is an attainment pollutant and the project would not impact the CO attainment status.

and SO_2) are considered significant and must be mitigated. Second, any AAQS violation or any contribution to any AAQS violation caused by any project emissions is considered to be significant and must be mitigated. For construction emissions, the mitigation that is considered is limited to controlling both construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, the mitigation includes both feasible emission controls (BACT) and the use of emission reduction credits to offset emissions of nonattainment criteria pollutants and their precursors.

The ambient air quality standards that staff uses as a basis for determining project significance are health-based standards established by the ARB and U.S. EPA. They are set at levels to adequately protect the health of all members of the public, including those most sensitive to adverse air quality impacts such as the aged, people with existing illnesses, children, and infants, including a margin of safety.

DIRECT/INDIRECT IMPACTS AND MITIGATION

While the emissions are the actual mass of pollutants emitted from the project, the impacts are the concentration of pollutants from the project that reach the ground level. When emissions are expelled at a high temperature and velocity through the relatively tall stack, the pollutants would be significantly diluted by the time they reach ground level. The emissions from the proposed project are analyzed through the use of air dispersion models to determine the probable impacts at ground level.

Air dispersion models provide a means of predicting the location and ground level magnitude of the impacts of a new emissions source. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions to provide theoretical maximum offsite pollutant concentrations short-term (1-hour, 3-hour, 8-hour, and 24-hour) and annual periods. The model results are generally described as maximum concentrations, often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$).

The applicant has used two models; EPA-approved American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) developed by the American Meteorological Society and Environmental Protection Agency for criteria pollutant modeling and HARP Version 1.3 software published by ARB for the health risk assessment. The AERMOD model is a steady-state Gaussian plume model which incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain. Pollutants concentrations for a wide range of averaging times (from 1 hour to 1 year) can be estimated by this model. The HARP software, based on the EPA Industrial Source Complex Short Term Version 3 (ISCST3) air dispersion model, consists of an air emission inventory module, an air dispersion module and a risk evaluation module.

Staff added the applicant's modeled impacts to the available highest ambient background concentrations as shown in **Air Quality Table 10**. Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or would contribute to an existing violation.

In general, the inputs for the modeling include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Gregory Canyon Landfill site, which is the closest complete meteorological data source to the project site, and is meteorological data approved for use by the SDAPCD.

Construction Impacts and Mitigation

The following section discusses the project's short-term direct construction ambient air quality impacts, as estimated by the applicant, and provides a discussion of appropriate mitigation. Staff reviewed the construction emissions estimates and air dispersions modeling procedures and considers them to be adequate and generally conservative for this siting case.

Construction Impact Analysis

The applicant modeled the emissions of the OGP on-site construction using the latest version of EPA's approved air dispersion modeling system, AERMOD (Version 07026).The fuel combustion emissions from construction equipment and the fugitive dust emissions were modeled as four volume sources and 13 distinct volume sources respectively.

For the determination of one-hour average construction NOx concentrations the applicant used an Ozone Limiting Method (OLM) Calculation that multiplied the maximum modeled NOx value by the assumed initial NO_2/NOx ratio of 0.1 for diesel equipment and added the conversion of NO to NO_2 based on the background ozone concentration that corresponded to the maximum NOx impact hour.

To determine the construction impacts on short-term ambient standards (i.e. 1-hour through 24 hours) the worst-case daily on-site construction emission levels shown in **Air Quality Table 11** were modeled. **Air Quality Table 21** provides the results of modeling analysis for the criteria pollutants during different averaging time period. Typical construction activities would occur from 7:00am to 5:30pm, however, modeling assumed a 12-hour workday to be conservative. (OGE 2008a).

Air Quality Table 21
OGP Construction Impacts, (µg/m3)

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$) [b]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Type of Standard	Percent of Standard
NO_2 [a]	1 hour	79.3	143.1	222.4	339	CAAQS	66%
	Annual	0.56	32.3	32.9	57	CAAQS	58%
PM10	24 hour	8.28	57	65.3	50	CAAQS	131%
	Annual	0.31	24.2	24.5	20	CAAQS	123%
PM2.5	24 hour	1.06	37.7	38.8	35	NAAQS	111%
	Annual	0.088	12	12.1	12	CAAQS	101%
CO	1 hour	170.7	6,785	6,956	23,000	CAAQS	30%
	8 hour	27.3	4,011	4,038	10,000	CAAQS	40%
SO_2	1 hour	0.33	94.3	94.6	655	CAAQS	14%
	3 hour	0.13	84.9	85.0	1,300	NAAQS	7%
	24 hour	0.017	23.6	23.6	105	CAAQS	22%
	Annual	0.0007	10.7	10.7	80	NAAQS	13%

Source (OGE 2008a)
[a] One-hour NOx value was determined using Ozone Limiting Method calculation. Staff adjusted the annual value by multiplying by the Annual NOx Ratio Method (ARM) U.S. EPA default value of 0.75.
[b] Background values have been adjusted per staff recommended background concentrations shown in AIR QUALITY Table 10.

As can be seen from the modeling results provided in **Air Quality Table 21**, the construction impacts have the potential to worsen the existing violations of the PM10 and PM2.5 ambient air quality standards and are, therefore, potentially significant. The applicant's construction modeling analysis indicates that the maximum NOx, CO and SO_2 impacts would remain below the CAAQS and NAAQS.

The maximum construction impacts occur at the property fence line. The maximum residential receptor impacts would be considerably lower due to the distance to the nearest residential receptor.

Construction Mitigation

Staff recommends that construction emission impacts be mitigated to the greatest feasible extent including all required measures from the District's rules and regulations, as well as other measures considered necessary by staff to fully mitigate the construction emissions. The District is currently in the process of creating a fugitive dust control rule (Rule 55) patterned on the recently promulgated Ventura County Air Pollution Control District fugitive rule, which may be approved and in force prior to the project starting or completing construction activities. However, the District has indicated that the Energy Commission conditions, as reviewed from other similar projects, would require control measures that would be as strict as or stricter than the anticipated requirements of District Rule 55 (Hamilton 2008).

Applicant's Proposed Mitigation

The applicant also has proposed most of the onsite mitigation monitoring, monthly reporting, and fugitive dust mitigation measures generally proposed by staff, and as recommended by staff for this case as Conditions of Certification **AQ-SC1** through **AQ-SC4** (OGE 2008a, p 20-23). The applicant has also proposed construction equipment mitigation that relies on pollution control retrofit for older construction equipment as required by ARB's Regulation for In-Use Off-Road Diesel Vehicles[4]. Other applicant proposed construction equipment mitigation measures, such as idle control, proper maintenance and use of California low sulfur diesel fuel (OGE 2008a, p 23-24).

Adequacy of Proposed Mitigation

The applicant's proposed mitigation monitoring, monthly reporting, and fugitive dust mitigation measures are almost identical to those generally proposed by staff, so they are with minor modifications considered adequate. However, the construction equipment mitigation measure's reliance on the ARB regulation that cover's equipment fleet manufacturer's average fleet composition does not regulate equipment at a specific project site. Therefore, staff does not believe that this approach would provide an assurance of adequate mitigation at the project site. The modeling analysis shows that the mitigated construction PM10 impacts are predicted to be potentially significant beyond the project fence line and the construction activities also emit precursors of the non-attainment pollutant ozone. Therefore, staff believes that all reasonable feasible construction emission mitigation measures are needed to mitigate the potentially significant construction PM10 and ozone impacts.

Staff Proposed Mitigation

Staff recommends construction emission mitigation measures that are nearly identical to the mitigation monitoring, monthly reporting, and fugitive dust mitigation measures proposed by the applicant (**AQ-SC1** to **AQ-SC4**), and an additional construction equipment mitigation measure to assure maximum feasible equipment exhaust emissions control (**AQ-SC5**).

Staff recommends **AQ-SC1** to require the applicant to have an on-site construction mitigation manager who would be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the construction mitigation program would be provided in the monthly construction compliance report that is required in staff's recommended Condition of Certification **AQ-SC2**.

Staff's recommended fugitive dust mitigation measures (**AQ-SC3** and **AQ-SC4**) generally incorporate the applicant's proposed fugitive dust mitigation measures.

Staff recommends Condition of Certification **AQ-SC5** to mitigate the NOx and PM emissions from the large diesel-fueled construction equipment. This condition requires the use of U.S. EPA/ARB Tier 2 engine compliant equipment for equipment over 100 horsepower where available and a good faith effort to find and use available U.S. EPA/ARB Tier 3 engine compliant equipment over 100 horsepower. The Condition also includes equipment idle time restrictions and engine maintenance provisions. The Tier 2 standards include engine emission standards for NOx plus non-methane hydrocarbons, CO, and PM emissions, while the Tier 3 standards further reduce the NOx plus non-

[4] http://www.arb.ca.gov/msprog/ordiesel/ordiesel.htm.

methane hydrocarbons emissions. The Tier 2 and Tier 3 standards became effective for engine/equipment model years 2001 to 2003 and models years 2006 to 2007, respectively, for engines between 100 and 750 horsepower.

Operation Impacts and Mitigation

The following section discusses the project's direct ambient air quality impacts, as estimated by the applicant, and evaluated by staff. Additionally, this section discusses the recommended mitigation measures.

The applicant performed direct impact modeling analyses, including operations, fumigation, and initial commissioning impact modeling.

Operational Modeling Analysis

Several combinations of operating conditions were evaluated to determine the maximum short-term operating impacts for the facilities. These included combinations of start/stop emission hours for the turbines and normal operation using 50, 75 and 100% load stack parameters (temperature and velocity, etc.). All of these modeling scenarios included representative emission from the auxiliary equipment (cooling tower and emergency engines).

The following short-term operating conditions were found to indicate the maximum short-term emission impacts for each pollutant.

For NOx:

100% base load for both turbines

For CO:

50% Load Start/Stop Mode for both turbines

For PM2.5, PM10, and SO_2:

100% base load for both turbines

In the case of NOx emission impacts the emergency engines, rather than the gas turbines, were the main contributor of the 1-hour short-term impacts.

AERMOD (Version 07026) and the meteorological data provided by SDAPCD were used for the modeling analysis. The applicant's predicted maximum concentrations of the non-reactive pollutants for the Orange Grove project are summarized in **Air Quality Table 22.**

Air Quality Table 22
OGP Maximum Operating Impacts, (μg/m³)

Pollutant	Averaging Period	Project Impact (μg/m³)	Background (μg/m³) [a]	Total Impact (μg/m³)	Limiting Standard (μg/m³)	Type of Standard	Percent of Standard
NO_2 [b]	1 hour	58.3	143.1	201.4	339	CAAQS	59%
	annual	0.35	32.3	32.7	57	CAAQS	57%
PM10[c]	24 hour	2.95	57	60.0	50	CAAQS	120%
	annual	0.26	24.2	24.5	20	CAAQS	123%
PM2.5[c]	24 hour [d]	2.12	37.7	39.8	35	NAAQS	114%
	annual	0.26	12	12.3	12	CAAQS	103%
CO	1 hour	109	6,785	6,894	23,000	CAAQS	30%
	8 hour	22	4,011	4,033	10,000	CAAQS	40%
SO_2 [c]	1 hour	6.7	94.3	101.0	655	CAAQS	15%
	3 hour	3.6	84.9	88.5	1,300	NAAQS	7%
	24 hour	0.94	23.6	24.5	105	CAAQS	23%
	annual	0.082	10.7	10.8	80	NAAQS	13%

Source: (OGE 2008a).
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.
[b] One-hour NOx value was determined using Ozone Limiting Method calculation. Staff adjusted the annual value by multiplying by the Annual NOx Ratio Method (ARM) U.S. EPA default value of 0.75.
[c] The PM10 and PM2.5 modeling results have been corrected following the change of the base load PM10 emission factor of 2.7 lbs/hour to 3.0 lbs/hour. This resulted in the modeled vs. permitted gas turbine particulate emissions increasing from 132.8 lbs/day to 144 lbs/day and from 8.78 tons/year to 9.6 tons per year. The ratio of these pollutant corrections were used to update the PM10 and PM2.5 modeling results.
[d] The PM2.5 results are the high eighth high value to represent the 98th percentile impact that correspond to the 98th percentile ambient air quality standard and background concentration. The PDOC provides a somewhat different value for this impact (2.53 μg/m³).

The applicant's modeling results indicate that the project's normal operational impacts would not create violations of NO_2, SO_2, or CO standards, but could further exacerbate violations of the PM10 and PM2.5 standards. In light of the existing PM10 and PM2.5 non-attainment status for the project site area, staff considers the modeled impacts to be significant and, therefore, require mitigation.

Initial Commissioning Short-Term Modeling Impact Analysis

The applicant presented several initial commissioning activities that would occur prior to meeting normal emission limits. The worst case conditions for the short-term NOx and CO impacts, as provided in the discussion prior to and after **Air Quality Tables 13**, were determined and modeled (OGE 2008a). The initial commissioning activities are limited to only one unit at a time operating without fully functioning emission controls. The AERMOD model was used for the commissioning impact analysis. Total of 35 cases of turbine operating conditions were evaluated to determine the worst-case emissions as shown in **Air Quality Table 23**.

Air Quality Table 23
OGP Maximum Short-Term Initial Commissioning Impacts, (μg/m^3)

Pollutant	Averaging Period	Project Impact (μg/m^3)	Background (μg/m^3) [a]	Total Impact (μg/m^3)	Limiting Standard (μg/m^3)	Type of Standard	Percent of Standard
NO_2 [b]	1 hour	70.9	143.1	214	339	CAAQS	63%
CO	1 hour	99.7	6,785	6,885	23,000	CAAQS	30%
	8 hour	20.4	4,152	4,172	10,000	CAAQS	42%

Source: (OGE 2008a).
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.
[b] One-hour NOx value was determined using Ozone Limiting Method calculation.

These modeling results indicate that no significant short-term impacts would occur during initial commissioning.

Fumigation Impact Analysis

Short-term impacts from fumigation can occur when the sun first rises, where the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air would also be vertically mixed, bringing some of those emissions down to the ground level. The applicant did not model the potential for fumigation impacts using the SCREEN3 model; however, based on past modeling analyses for stacks with high temperature and high velocity such as the OGP, fumigation impacts would be less than the worst-case short-term impacts predicted by AERMOD. For example, the nearly identical Chula Vista Energy Upgrade Project (CVEUP) did model fumigation impacts and found that they were considerably lower than the maximum impacts determined by AERMOD (CEC 2008o, p. 4.1-36). The fumigation modeling results for this project would be very similar to that performed for CVEUP; therefore, the short-term fumigation impact potential would be less than significant.

Chemically Reactive Pollutant Impacts

Ozone Impacts

The project's gaseous emissions of NOx, SO_2, VOC, and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5.

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the OGP do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts would be cumulatively significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards.

PM2.5 Impacts

Secondary particulate formation, which is assumed to be 100% PM2.5, is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first and then react with ambient ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid and converts completely and irreversibly to particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase will tend to fall out; however, the gas phase can revert back to ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air. There are two conditions that are of interest, described as *ammonia rich* and *ammonia poor*. The term ammonia rich indicates that there is more than enough ammonia to react with all the sulfuric acid and to establish a balance of nitric acid-ammonium nitrate. Further ammonia emissions in this case would not necessarily lead to increases in ambient PM2.5 concentrations. In the case of an ammonia poor environment, there is insufficient ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

The San Diego Air Basin has not undergone the rigorous secondary particulate studies that have been performed in other areas of California, such as the San Joaquin Valley, that have more serious fine particulate pollution problems. However, the available chemical characterization data shows that the annual ammonium nitrate and ammonium sulfate fine particulate concentrations in Escondido and San Diego range from approximately 50-60% of the state annual ambient standard (ARB 2005). Because of the known relationship of NOx and SOx emissions to PM2.5 formation, it can be said that the emissions of NOx and SOx from the OGP do have the potential (if left unmitigated) to contribute to higher PM2.5 levels in the region.

Additionally, there would certainly be some secondary particulate conversion from the ammonia emitted from the OGP project; however, there is currently no regulatory model that can predict the conversion rate. Therefore, it is recommended that ammonia emissions be limited to the extent feasible, while ensuring that the selective catalytic reduction unit maintains NOx emissions below the required controlled concentration limit of 2.5 ppm.

The applicant is proposing to mitigate the project's NOx, VOC, SO_2, and PM10 emissions through the use of BACT and emission reduction strategies and limit the ammonia slip emissions to 5 ppm. The applicant proposes to provide total NOx, VOC, SO_2, and PM10 reductions at a minimum 1:1 ratio, and the ammonia slip concentration level matches the lowest level proposed in California for a peaking power project. With the proposed emission offsets and ammonia slip limit, it is staff's belief that the project would not cause significant secondary pollutant impacts.

Operations Mitigation

Applicant's Proposed Mitigation

Emission Controls

As discussed in the **Project Description** section, the applicant proposes to employ water injection, SCR with ammonia injection, and CO catalyst and operate exclusively on pipeline-quality natural gas to limit turbine emission levels (OGE 2008a). The applicant has proposed the following BACT emission limits, each for the two CTGs:

- NOx: 2.5 ppmvd at 15% O_2 (one-hour average, excluding startup/shutdown) and 4.30 lb/hr
- CO: 6.0 ppmvd at 15% O_2 (three-hour rolling average, excluding startup/shutdown) and 6.12 lb/hr
- VOC: 2.0 ppmvd at 15% O_2 (one-hour rolling average, excluding startup/shutdown) and 1.25 lb/hr
- PM10: 2.7 lb/hr (as proposed by the applicant, the PDOC assumes 3.0 lb/hr)
- SO_2: 1.0 lb/hr with fuel sulfur content of 0.75 grains/100 standard cubic feet (scf)
- NH_3: 5 ppmvd at 15% O_2 and 3.01lb/hr

For the chiller cooling tower a mist eliminator with a 0.001% control efficiency is proposed.

For the emergency fire pump engine a diesel engine meeting U.S.EPA/ARB Tier 2 Nonroad Diesel Engine Emission Standards is proposed. For the black-start engine a rich-burn natural gas engine is proposed. The proposed emission guarantees for the two emergency engines are as follows.

Air Quality Table 24
Proposed Emergency Engine Emission Rates [a]

Pollutant	Fire Pump Engine		Black-Start Engine	
	g/bhp	Lb/test[b]	g/bhp	Lb/test[b]
NOx	3.84	1.58	1.50	1.39
CO	0.746	0.31	2.00	1.85
VOC	0.0007	0.0003	0.33	031
PM10/PM2.5	0.091	0.04	0.010[c]	0.04

From OGE 2008a.
[a] SO_2 emissions do not have emission guarantees and are based on the use of California low sulfur content diesel fuel (15 ppm sulfur) for the fire pump engine and pipeline natural gas for the black-start engine.
[b] The test duration for both engines is one half hour in duration.
[c] Emission factor is based on lbs/MMBtu.

Emission Offsets

District Rule 20 requires offsets when NOx or VOC emissions exceed 50 tons per year. The emissions from this project would be permitted at levels well below the District offset threshold.

Energy Commission staff has long held that emission reductions need to be provided for all nonattainment pollutants and their precursors at a minimum 1:1 ratio of annual operating emissions. For this project, the District's regulations would not require any offset mitigation. The applicant has agreed to funding emission reductions through the Carl Moyer Fund or similar mechanism as proposed by staff for the Chula Vista siting case (CEC 2008o). The applicant's amended proposal includes a determination of the new project emissions based on the new facility's potential to emit given a maximum expected operations of 1,200 operating hours per year that includes 200 startup and shutdown events. The applicant's amended offset proposal is as follows (TRC 2008f):

- Total calculated emission increase of 12.72 tons (total of NOx, VOC, PM, and SOx emissions), which includes the water truck emissions;
- Fund the Carl Moyer program at a rate of $16,000 per ton with a 20% additional administration fee.

Using this basis, the total emission reduction funding proposed by the applicant is $244,224.

Adequacy of Proposed Mitigation

Staff concurs with the District's determination that the project's proposed emission controls/emission levels for criteria pollutants and ammonia slip meets BACT requirements and that the proposed emission levels are reduced to the lowest technically feasible levels.

Staff has made a preliminary determination that the applicant's amended offset proposal approach, which is a stipulation to the general approach recommended for the Chula Vista Energy Upgrade Project, meets CEQA mitigation requirements. Staff's acceptance of this offset package was determined solely based on the merits of this case, consideration of the region's local ambient air quality and expected attainment timelines, the project's expected operation and resulting emission limits, and the specific form of emission reductions proposed and does not in any way provide a precedent or obligation for the acceptance of offset proposals for any other current or future licensing case.

Staff has determined that the proposed emission controls and emission levels, along with the proposed emission offset package, mitigate all project air quality impacts to less than significant.

Staff has considered the minority population surrounding the site (see **Socioeconomics** Figure 1). Since the project's direct air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

Staff Proposed Mitigation

Staff is proposing Condition of Certification **AQ-SC6** to formalize the applicant's amended emission offset proposal.

Staff evaluated the applicant's original proposal's assumption for likely maximum annual operation, 1,000 hours or a capacity factor of 11.4%, and found data to support using a reduced capacity factor in this general range given the historical capacity factors and the worst-case forecast capacity factors for SDG&E service area peaker facilities. The historical capacity factors, for peaker power plants built after the year 2000, found in a review of the Energy Commission's Quarterly Fuel and Energy Reporting data and available SDAPCD 2005 and 2006 data (Moore 2008) show generation or hour-based capacity factors that have not exceeded 8.4% for any single facility. The historical capacity factor data reviewed is provided in **Air Quality Table 25**.

Air Quality Table 25
Historical Capacity Factors for Comparable SDG&E Service Area Peaker Facilities

	QFER Generation Based Capacity Factor					
Facility Name	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Calpeak Border	7.77%	2.71%	2.28%	1.86%	1.43%	8.39%
Calpeak Enterprise	7.53%	2.18%	2.35%	1.55%	1.24%	5.76%
Larkspur	1.18%	4.01%	4.74%	3.85%	2.89%	6.00%
	SDAPCD Hours of Operation Capacity Factor					
Facility Name	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Calpeak Border	---	---	---	2.29%	1.72%	---
Calpeak Enterprise	---	---	---	1.91%	1.49%	---
Calpeak El Cajon	---	---	---	2.64%	2.26%	---
Miramar Energy Facility	---	---	---	1.69%	1.84%	---
Larkspur	---	---	---	4.41%	3.51%	---

Source: Energy Commission QFER data; Moore 2008

The most comparable facility to the OGP is Larkspur as it is also comprised of two LM6000 gas turbines.

Staff also reviewed the worst-case SDG&E service area peaker capacity factors forecast in the Scenario Analysis of California's Electricity System performed for the *2007 Integrated Energy Policy Report* (CEC 2007a). The worst-case generation based capacity factors for the existing and named peakers for 2009 to 2020 range from 5.7 - 10.5%. It is important to note that the generation based capacity factors could be lower than emission based capacity factors due to higher proportional emissions during reduced load conditions and start/shut-down periods. Using these historic and forecast capacity factor data sources and considerations regarding emissions versus generation or hourly operation capacity factors, staff has determined that a 13.7% annual capacity factor, or 1,200 hours of operation, with two hundred startup and two hundred shutdown events, would provide a reasonable safety margin for the determination of CEQA emission mitigation requirements for this project. This is similar to, but somewhat higher than, 1,000 hours originally proposed by the applicant. The applicant has stipulated to agreeing to staff's offset proposal (TRC 2007f).

Staff also believes that the mitigation fee basis should be tied to ARB's latest Carl Moyer Program Guideline[5] cost effectiveness cap value. The draft ARB 2008 cost effectiveness cap value is $16,000 per ton (ARB 2008d). **AQ-SC7** is written to allow flexibility should the final cost effectiveness cap value change from the draft value. Additionally, **AQ-SC7** has also been designed to allow other public agency administered

[5] The ARB Carl Moyer Web page has the following description of the program: "The Carl Moyer Memorial Air Quality Standards Attainment Program provides incentive grants for cleaner-than-required engines, equipment and other sources of pollution providing early or extra emission reductions. Eligible projects include cleaner on-road, off-road, marine, locomotive and stationary agricultural pump engines, as well as forklifts, airport ground support equipment, and auxiliary power units. The program achieves near-term reductions in emissions of oxides of nitrogen (NOx), particulate matter (PM), and reactive organic gas (ROG) which are necessary for California to meet its clean air commitments under the State Implementation Plan Program funds" (ARB 2008e).

emission mitigation fee programs or traditional emission reduction credits (ERCs) from the District bank to be used to meet the emission mitigation requirement of the condition.

Staff would like to note that the CEQA mitigation basis includes a rather significant safety factor, namely the difference between the project's actual emissions and its proposed maximum emissions. The actual emissions from a LM6000 gas turbine would be some fraction of the permitted maximum emissions. Some pollutants are emitted near their permitted emission rate, such as NOx, while others tend to be much lower than their permitted emission rate, such as VOC and CO. **Air Quality Table 26** provides a comparison of the OGP permitted emission rates and an expected actual range of emissions and average normal hourly operating emissions for two LM6000 gas turbines based on a compilation of source test results (from four separate sites with LM6000PC Sprint gas turbines), and the expected safety factor for each pollutant.

Air Quality Table 26
Comparison of Actual and Permitted Emissions for OGP and Existing Turbines

	Pollutant lb/hr Normal Operations [a] or % as appropriate			
Emission Source	**NOx**	**VOC**	**CO**	**PM10/2.5**
OGP LM6000 Permitted Emissions (both Turbines)	8.6	2.5	12.2	5.4
Existing LM6000 Two Turbine Actual Emissions Range [b]	NR	0.11-1.8	0.93-4.5	0.72-4.9
Existing LM6000 Two Turbine Actual Emissions Average [c]	NR	0.72	2.5	2.3
Existing LM6000 Source Tests –% of Permit Level [c]	65%	30%	25%	38%
Expected OGP Permitted Emissions Safety Margin [d]	15%	70%	75%	50%
Expected Long-Term OGP Normal Operating Emissions	7.3	0.75	3.1	2.7

Sources: OGE 2008a for OGE permitted emissions and staff summary and analysis of existing LM6000PC Sprint gas turbine source test data for the Hanford, Henrietta, Los Esteros, and Donald Von Raesfeld facilities.
NR – Not representative. The NOx emission concentration limits for the four projects surveyed are different than the proposed OGP project so the mass emission rate is not representative. The percent of permit level however has been determined.
a – SOx emissions safety factor is the difference between the natural gas sulfur content used in the mitigation emission calculations (0.25 grains/100 scf) and the expected long-term fuel sulfur content, which is expected to be less than half of the assumed value.
b – Lowest and highest source test values from 10 LM6000PC Sprint gas turbines.
c – Average values from source tests from 10 LM6000 PC Sprint gas turbines.
d – Safety factor for NOx is conservatively assumed to be approximately one-half what would occur if the facility were to meet the average percent of permit level found for the four surveyed sources due to the lower concentration limit required for OGP.

Air Quality Table 26 shows that the actual emissions from the new LM6000 turbines are expected to be quite a bit lower than the permitted emissions, particularly for CO, VOC, and PM10 emissions, which provides a margin of safety for staff's proposed mitigation level.

Staff is proposing Condition of Certification **AQ-SC8** to ensure that the initial commissioning operations of the OGP are conducted in the 7 am to 7 pm hours stipulated by the applicant. The applicant has stipulated to this condition which limits the potential for air quality impacts not described in the applicant's modeling analysis, which assumed that commissioning would only occur between 7 am to 7 pm.

Staff is proposing Condition of Certification **AQ-SC9** and **AQ-SC10** to provide the chiller cooling tower mist eliminator performance standard and to require the applicant to conduct cooling tower water testing and provide emission reporting that are not required in the SDAPCD conditions, respectively.

Staff is proposing Conditions of Certification **AQ-SC7** and **AQ-SC11** that would ensure that the license is amended as necessary to incorporate changes to the air quality permits and ensure ongoing compliance through the requirement of quarterly reports.

Staff is proposing Condition of Certification **AQ-SC12** to formalize the applicant's stipulation to buy new water delivery trucks and to ensure that they will be properly maintained to minimize water trucking emissions.

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts" (CEQA Guidelines § 15355). "A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts" (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This analysis is primarily concerned with "criteria" air pollutants. Such pollutants have impacts that are usually (though not always) cumulative by nature. Rarely will a project cause a violation of a federal or state criteria pollutant standard. However, a new source of pollution may contribute to violations of criteria pollutant standards because of the existing background sources or foreseeable future projects. Air districts attempt to attain the criteria pollutant standards by adopting attainment plans, which comprise a multi-faceted programmatic approach to such attainment. Depending on the air district, these plans typically include requirements for air offsets and the use of best available control technology for new sources of emissions and restrictions of emissions from existing sources of air pollution.

Much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" subsection describes the air quality background in the San Diego Air Basin, including a discussion of historical ambient levels for each of the significant criteria pollutants. The "Construction Impacts and Mitigation" subsection discusses the project's contribution to the local existing background caused by project construction. The "Operation Impacts and Mitigation" subsection discusses the project's contribution to the local existing background caused by project operation. The following subsection includes four additional analyses:

- a summary of projections for criteria pollutants by the air district and the air district's programmatic efforts to abate such pollution;
- an analysis of the project's *localized cumulative impacts*, the project's direct operating emissions combined with other local major emission sources;

Summary of Projections

The SDAPCD is the lead agency for managing air quality and coordinating planning efforts for San Diego County and the San Diego Air Basin, so that the federal 8-hour ozone standard is attained in a timely fashion and attainment with CO standards are maintained. The District is responsible for developing those portions of the State Implementation Plan (SIP) and the Air Quality Management Plan (AQMP), that deal with certain stationary and area source controls and, in cooperation with the transportation planning agencies, the development of transportation control measures. Additionally, the SDAPCD is responsible for providing plans for attaining the California ozone standard and for reducing particulate (PM10 and PM2.5) emissions in compliance with Senate Bill 656 (Sher, Chapter 738, Statutes of 2003). In this role, the SDAPCD is the agency with principal responsibility for analyzing and addressing cumulative air quality impacts, including the impacts of ambient ozone, particulate matter, and CO. The District has summarized the cumulative impacts of ozone, particulate matter, and CO on the air basin from the broad variety of its sources. Analyses of these cumulative impacts, as well as the measures the District proposes to reduce impacts to air quality and public health, are summarized in six publicly available documents. These adopted air quality plans are summarized below.

- Eight-Hour Ozone Attainment Plan (federal 8-hour ozone attainment plan)
  Link: http://www.sdapcd.org/planning/8-Hour-Ozone-Attainment-Plan.pdf
- Air Resources Board's Proposed State Strategy for California's 2007 State Implementation Plan (federal 8-hour ozone attainment plan)
  Link: http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm
- Ozone Redesignation Request and Maintenance Plan (federal 1-hour ozone maintenance plan)
  Link: http://www.sdapcd.org/planning/RedesigPlan.pdf
- 2004 Revision to the California State Implementation Plan for Carbon Monoxide (federal CO maintenance plan)
  Link: http://www.arb.ca.gov/planning/sip/co/final_2004_co_plan_update.pdf
- 2004 Triennial Revision of the Regional Air Quality Strategy for San Diego County (state ozone attainment plan)
  Link: http://www.sdapcd.org/planning/RAQS-04.pdf
- Measures to Reduce Particulate Matter in San Diego County (Health and Safety Code 39614)
  Link: http://www.sdapcd.org/planning/SB656StaffRpt.pdf

The final 8-hour ozone attainment plan for San Diego County was submitted by the state in the ARB *Proposed State Strategy for California's 2007 State Implementation Plan* document in late 2007. This plan has not been approved by U.S. EPA, so the approved 1-hour plan is the currently approved ozone attainment plan for San Diego County. The 2007 State Implementation Plan, when approved by U.S. EPA, will become the ozone attainment plan for the District.

Eight-Hour Ozone Attainment Plan and Air Resources Board's Proposed State Strategy for California's 2007 State Implementation Plan

The District's Eight-Hour Ozone Attainment plan relies strongly on existing control measures included in District rules and regulations. The ARB's state proposed strategy for the State Implementation Plan relies primarily on existing control measures, as well as tightening vehicle emissions (both on- and off-road vehicles) and emissions from other transportation sources, pesticides, and consumer products. No new control strategies that are directly applicable to the project are noted in either of these two ozone planning documents. Indirectly, the on-road and off-road control measures would regulate some of the delivery vehicles and construction equipment used during the projects construction and operation. U.S. EPA has not yet approved the 8-hour ozone attainment plan for California.

Ozone Redesignation Request and Maintenance Plan

This plan was prepared after the SDAB came into compliance with the federal 1-hour ozone standard in December 2002. U.S. EPA approved this plan and redesignated the San Diego Air Basin as attainment with the 1-hour standard effective July 28, 2003. The specific control measures included in the approved 1-hour ozone maintenance plan are those that were approved for the nonattainment State Implementation Plan (SIP), and no new measures were proposed. The existing measures from the previously approved SIP are included in the District's rule and regulations and ARB vehicle emission regulations. Therefore, compliance with these rules and regulations would ensure that the project conforms to the 1-hour ozone maintenance plan.

While the San Diego area is no longer subject to the revoked federal 1-hour ozone standard, the 8-hour ozone plan has not yet been approved by U.S. EPA, so this plan is the currently approved ozone plan for San Diego County.

2004 Revision to the California State Implementation Plan for Carbon Monoxide

The Carbon Monoxide Maintenance Plan applies to 10 separate areas in California that attained the federal CO standards in the 1990s, including the San Diego area. This plan does not include any further measures or requirements that would specifically relate to the project's direct and indirect emission sources. This plan relies on current motor vehicle programs to ensure that attainment with the federal CO standards is maintained.

The project's construction and operation were not found to cause any new exceedances of the carbon monoxide ambient air quality standards (CO AAQS). The project's generated traffic would be insignificant in comparison with the existing San Diego County traffic, and the project's primary emission sources normally emit CO concentrations out of the stack that are below the federal ambient air quality standards. Therefore, the project would not impact the Carbon Monoxide Maintenance Plan.

2004 Triennial Revision of the Regional Air Quality Strategy for San Diego County

This plan is prepared to determine progress and measures needed to attain California Ambient Air Quality Standards (CAAQS) for ozone, carbon monoxide, nitrogen dioxide, and sulfur dioxide. San Diego County is in attainment with all of these state standards except ozone. This plan describes the extent of ozone air quality improvement during the previous three years, provides a discussion of actual versus forecasted emission rates, and evaluates the need for further control measures in order to achieve attainment with the state ozone ambient air quality standards. None of the measures determined for further study in this document would apply to the proposed project.

The draft triennial plan was completed in August 2008, but is has not yet been officially approved (SDAPCD 2008d). None of the emission reduction measures proposed in the draft document, which includes a Best Available Retrofit Control Technology (BARCT) measure for existing older peaker turbines and a control measure for small boilers (less than 5 million Btu/hr heat input), would impact the new gas turbines and internal combustion engines that would be installed as part of this project.

Measures to Reduce Particulate Matter in San Diego County

This plan, completed in December 2005, analyzed potential particulate control measures, listed by ARB, as required by Health and Safety Code 39614. The SDAPCD's review indicated that 59 of these ARB measures were already included in existing District rules and regulations, that 25 of these control measures would not significantly reduce particulate emissions in San Diego County, and that 19 of these control measures could have cost effective particulate reductions. The District will evaluate these 19 control measures further and will propose new regulations, or non regulatory programs, for consideration of the District Board, if appropriate. Of these 19 control measures, there are eight fugitive dust control measures that could be applicable to the project's construction activities, including earthmoving, demolition, grading, carryout and trackout, unpaved staging areas, and windblown dust controls. The District has not yet promulgated any regulations for fugitive dust control; however, a fugitive dust rule is planned to be promulgated prior to the end of the project's construction. Staff's proposed fugitive dust control measures (Conditions of Certification **AQ-SC3** and **AQ-SC4**) require stringent emission control measures for all of the applicable fugitive dust sources that are identified for further study in this planning document and that are likely to be included in the District's future fugitive dust control rule.

Summary of Conformance with Applicable Air Quality Plans

The applicable air quality plans do not outline any new control measures applicable to the proposed project's operating emission sources. Therefore, compliance with existing District rules and regulations would ensure compliance with those air quality plans.

SDAPCD is evaluating additional fugitive dust control measures that it plans to include in a new fugitive dust control rule that should be promulgated in a new Rule 55 either late in 2008 or early in 2009. Staff's recommended Conditions of Certification **AQ-SC3** and **AQ-SC4** include fugitive dust control measures that should meet or exceed the fugitive dust control requirements that are currently being considered by the District. However, **AQ-SC3** has been revised to include the potential that specific fugitive dust control measures that are required by future District Rule 55 could be more stringent than those currently required in staff's proposed conditions.

Localized Cumulative Impacts

Since the power plant air quality impacts can be reasonably estimated through air dispersion modeling (see the "Operational Modeling Analysis" subsection) the project contributions to localized cumulative impacts can be estimated. To represent *past* and, to an extent, *present projects* that contribute to ambient air quality conditions, the Energy Commission staff recommends the use of ambient air quality monitoring data (see the "Environmental Setting" subsection), referred to as the *background*. The staff takes the following steps to estimate what are additional appropriate "present projects" that are not represented in the background and "reasonably foreseeable projects":

- First, the Energy Commission staff (or the applicant) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within six miles of the project site. Based on staff's modeling experience, beyond six miles there is no statistically significant concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.
- Second, the Energy Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within six miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final Environmental Impact Reports (EIRs) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.
- The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources, provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.
- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than two miles away.
- The modeling results must be carefully interpreted so that they are not skewed towards a single source, in high impact areas near that source's fence line. It is not truly a cumulative impact of the OGP if the high impact area is the result of high fence line concentrations from another stationary source and OGP is not providing a substantial contribution to the determined high impact area.

Once the modeling results are interpreted, they are added to the background ambient air quality monitoring data and thus the modeling portion of the cumulative assessment is complete. Due to the use of air dispersion modeling programs in staff's cumulative impacts analysis, the applicant must submit a modeling protocol, based on information requirements for an application, prior to beginning the investigation of the sources to be modeled in the cumulative analysis. The modeling protocol is typically reviewed, commented on, and eventually approved in the Data Adequacy phase of the licensing procedure. Staff typically assists the applicant in finding sources (as described above), characterizing those sources, and interpreting the results of the modeling. However, the actual modeling runs are usually left to the applicant to complete. There are several reasons for this: modeling analyses take time to perform and require significant expertise, the applicant has already performed a modeling analysis of the project alone (see the “Operational Modeling Analysis” subsection), and the applicant can act on its own to reduce stipulated emission rates and/or increase emission control requirements as the results warrant. Once the cumulative project emission impacts are determined, the necessity to mitigate the project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the applicant (see the “Mitigation” subsection).

The cumulative assessment for OGP includes the two other sources shown in **Air Quality Table 27**.

Air Quality Table 27
Facilities Included in the Cumulative Modeling Analysis

Facility	Source Type
Rosemary’s Mountain Quarry	Rock Quarry, Processing and Asphalt Plant
Gregory Canyon Landfill	Sanitary Landfill

The original list of possible new sources from the SDAPCD included 2 sources (OGE 2008a). However, both of these sources, one in Vista and one in Escondido are considerably more than six miles from the site.

The applicant’s review of cumulative sources determined that the Rosemary’s Mountain Quarry and Gregory Canyon Landfill projects were proceeding and could potentially operate at the same time as the OGP. The applicant obtained emission and other available modeling parameter data for these two projects and followed the same modeling procedures used for the OGP operating emissions modeling analysis, using the most recent version of AERMOD (Version 07026). The modeled receptors cover the area surrounding the OGP for several miles, which also covers these two projects which are both located less than two and a half miles from the OGP site.

The modeling assumed worst-case short-term emissions for the OGP (cold startup) and the normal operating emissions for the other two projects for the short-term impact modeling and permitted annual average emissions for the OGP and estimated annual emissions for the two other projects for annual impact modeling. Carbon monoxide and SO_2 were not modeled due to the low project impacts. The results of the applicant’s cumulative modeling analysis, OGP cumulative peak results basis, are provided in **Air Quality Table 28**.

Air Quality Table 28
OGP Based Peak Cumulative Impacts Modeling Results ($\mu g/m^3$)

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$) [a]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Type of Standard	Percent of Standard
NO_2[b]	1 hour	50.0	143.1	193.1	339	CAAQS	57%
	annual	0.19	32.3	32.5	57	CAAQS	57%
PM10[c]	24 hour	1.3	57	58.3	50	CAAQS	117%
	annual	0.12	24.2	24.3	20	CAAQS	122%
PM2.5[c]	24 hour	1.3	37.7	39.0	35	NAAQS	111%
	annual	0.12	12	12.1	12	CAAQS	101%

Source: OGP Cumulative Assessment (OGE 2008e).
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 10**.
[b] One-hour NOx value was determined using Ozone Limiting Method calculation. Staff adjusted the annual value by multiplying by the Annual NOx Ratio Method (ARM) U.S. EPA default value of 0.75.
[c] The PM10 and PM2.5 modeling results for OGP have been corrected following the change of the base load PM10 emission factor of 2.7 lbs/hour to 3.0 lbs/hour. This resulted in the modeled vs. permitted gas turbine particulate emissions increasing from 132.8 lbs/day to 144 lbs/day and from 8.78 tons/year to 9.6 tons per year. The ratio of these pollutant corrections were used to update the PM10 and PM2.5 modeling results. PM2.5 was not actually modeled separately so it is conservatively assumed that PM10 = PM2.5.

The results of this modeling effort, **Air Quality Table 28**, show that OGP, along with the other two modeled facilities, would contribute to existing violations of the PM10 and PM2.5 ambient air quality standards. The impacts are lower than those shown in **Air Quality Table 22** due to a coarser receptor grid that was used to better identify cumulative overlap between the projects rather than determine the exact peak concentration for the project. The overlap between the three projects is very low and does not cause new standards violations. The overlap in NOx and PM impacts between the projects is provided in **Air Quality Table 29**.

Air Quality Table 29
Cumulate Project Concentration Overlap ($\mu g/m^3$)

Pollutant	Project	OGP Peak	RMQ Peak	GCL Peak
NOx 1-hour	OGP	50.0	0.3	0.0
	GCL	0.0	0.4	106.7
	RMQ	0.0	86.7	0.0
	Total	50.0	78.1 [a]	160.1 [a]
NOx Annual	OGP	0.143	0.004	0.001
	GCL	0.023	0.026	0.167
	RMQ	0.026	0.361	0.018
	Total	0.192	0.391	0.186
PM 24-hour	OGP	1.22	0.00	0.00
	GCL	0.01	0.19	4.62
	RMQ	0.02	4.85	0.14
	Total	1.25	5.04	4.76
PM Annual	OGP	0.079	0.002	0.001
	GCL	0.020	0.080	0.335
	RMQ	0.017	0.232	0.015
	Total	0.116	0.315	0.351

Source: OGE 2008e
RMQ – Rosemary's Mountain Quarry, GCL – Gregory Canyon Landfill
[a] The total is less than the maximum or sum due to how the AERMOD OLM program works, where the reaction rate is a function of both the hourly ozone concentration and the mass of NOx in the plume, so increasing the NOx through multiple sources changes the reaction rate and creates a non-linear result.

The applicant's modeling results determined for the Rosemary's Mountain Quarry based peak concentrations and the Gregory Canyon Landfill peak concentrations, as shown in **Air Quality Table 29**, indicate extremely low overlap between the OGP and the maximum concentrations (OGP contributes less than 1% of those peak concentrations). The modeling also show that OGP, along with the other two modeled facilities, would not contribute to any new NOx AAQS violations (OGE 2008e).

The OGP would mitigate their PM10 and particulate precursor pollutant (NOx, SOx, and VOC) emissions through funded emission reductions. These emission reductions would be generated in amounts greater than the expected operating emissions. Therefore, the particulate matter (PM10 and PM2.5) OGP cumulative operating impacts after mitigation are considered to be less than significant.

Staff has considered the minority population surrounding the site (see **Socioeconomics Figure 1**). Since the project's cumulative air quality impacts have been mitigated to less than significant, there is no environmental justice issue for air quality.

COMPLIANCE WITH LORS

The San Diego Air Pollution Control District issued a Preliminary Determination of Compliance (PDOC) for the OGP on October 8, 2008 (SDAPCD 2008c). Compliance with all District rules and regulations was demonstrated to the District's satisfaction in the PDOC. The District's PDOC conditions are presented in the Conditions of Certification (**AQ-1** to **AQ-93**).
Energy Commission staff will provide comment on the PDOC to the District and will reflect any major changes to compliance with LORS in an addendum to the Staff Analysis that will be published some time after the Final Determination of Compliance (FDOC) has been published by the District, which is assumed to occur in mid-November.

FEDERAL

The District is responsible for issuing the federal New Source Review (NSR) permit but has not yet been delegated enforcement of the applicable New Source Performance Standard (Subpart KKKK). This project would not require a PSD permit from U.S. EPA prior to initiating construction.

STATE

The applicant would demonstrate that the project would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, with the issuance of the District's Final Determination of Compliance and the Energy Commission's affirmative finding for the project.

The fire pump engine is also subject to the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines. This measure limits the types of fuels allowed, established maximum emission rates, establishes recordkeeping requirements. The proposed Tier 2 engine meets the emission limit requirements of this rule. This measure would also limit the engine's testing and maintenance operation to 50 hours per year.

LOCAL

The District rules and regulations specify the emissions control and offset requirements for new sources such as the OGP. Best Available Control Technology would be implemented, and emission reduction credits (ERCs) are not required by District rules and regulations based on the permitted emission levels for this project. Compliance with the District's new source requirements would ensure that the project would be consistent with the strategies and future emissions anticipated under the District's air quality attainment and maintenance plans.

The applicant provided an air quality permit application to the SDAPCD in 2007 when the siting case was in the Small Power Plant Exemption process. They provided additional information to the District when they filed the AFC in June 2008. The District has issued a PDOC (SDAPCD 2008c), which states that the proposed project is expected to comply with all applicable District rules and regulations. The FDOC will be published after completion of a 30-day public review period ending November 7, 2008. The DOC evaluates whether and under what conditions the proposed project would comply with the District's applicable rules and regulations, as described below.

Regulation II – Permits

Rule 20.1 and 20.2 – New Source Review

Rules 20.1 and 20.3 generically apply to all sources subject to permitting under the nonattainment NSR and PSD programs. All portions of Rule 20.1 apply. This includes definitions and instructions for calculating emissions. Applicable components of Rule 20.2 are described below. Rule 20.3, which includes the requirements for offsets are only applicable to major stationary sources. The District has determined that this is not a major stationary source as defined in Rule 20.1; so Rule 20.3, including offset requirements, does not apply to the OGP.

Rule 20.2(d)(1) – Best Available Control Technology/Lowest Achievable Emission Rate

This subsection of the rule requires that BACT be installed on a pollutant specific basis if emissions exceed 10 lbs/day for each criteria pollutant (except for CO, for which the PSD BACT threshold is 100 tons per year). This subsection also requires that Lowest Achievable Emission Rate (LAER) be installed on a pollutant specific basis if the emissions exceed 50 tons per year for NOx (oxides of nitrogen) or VOC emissions. Because the District attains the national ambient air quality standards for CO, SO_2, and PM10, LAER does not apply to these particular pollutants (District Rule 20.3[d][1][v]). The OGP NOx and VOC emissions are below the trigger for LAER. BACT is required for NOx, VOC, PM10, and SOx. In the PDOC, the District has determined that the proposed SCR and oxidation catalyst emission controls are BACT for gas turbines. The other emissions sources (emergency engines and cooling tower) do not trigger BACT.

Rule 20.2(d)(2) – Air Quality Impact Analysis

This portion of the rule requires that an Air Quality Impact Analysis (AQIA) be performed for air contaminants that exceed the trigger levels published in Table 20.3-1 of the District's rules and regulations. For an AQIA of PM10, the rules require that direct emissions and emissions of PM10 precursors be included in the analysis.

The OGP has prepared an AQIA for NOx, CO, and PM10 that was evaluated by District staff as part of the PDOC analysis.

Rule 20.2(d)(4) – Public Notice and Comment

This portion of the rule requires the District to publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County. The District must allow at least 30 days for public comment and consider all comments submitted. The District must also make all information regarding the evaluation available for public inspection.

The official public notice and comment period for the OGP started after newspaper notice publication on October 9, 2008, and ends on November 7, 2008.

Rule 20.5 – Power Plants

This rule requires that the District prepare a decision of Preliminary and Final Determinations of Compliance (PDOC and FDOC), which shall confer the same rights and privileges as an Authority to Construct only after successful completion of the Energy Commission's licensing process.

Regulation IV – Prohibitions

Rule 50 – Visible Emissions

This rule prohibits air contaminant emissions into the atmosphere darker than Ringelmann Number 1 (20% opacity) for more than an aggregate of three minutes in any consecutive 60-minute time period. In the PDOC, the District has determined that the facility is expected to comply with this rule.

Rule 51 – Nuisance

This rule prohibits the discharge of air contaminants that cause or have a tendency to cause injury, detriment, and nuisance or annoyance to people and/or the public or damage to any business or property. In the PDOC, the District has determined that the facility is expected to comply with this rule.

Rule 52 – Particulate Matter

This rule is a general limitation for all sources of particulate matter to not exceed 0.10 grains per dry standard cubic foot (0.23 grams per dry standard cubic meter) of exhaust gas. Stationary internal combustion engines are exempt from this requirement. The district did not calculate the grain loading for the cooling tower, which would be subject to this rule, but staff has calculated the grain loading to be 0.000031 grains per dry standard, well within the grain loading standard and in compliance with the requirements of this rule.

Rule 53 – Specific Air Contaminants

This rule limits emissions of sulfur compounds (calculated as SO_2) to less than or equal to 0.05%, by volume, on a dry basis. The use of pipeline-quality natural gas fuel would ensure compliance with the sulfur compound emission limitation of this rule.

This rule also contains a limitation restricting particulate matter emissions from gaseous fuel combustion to less than or equal to 0.10 grains per dry standard cubic foot of exhaust calculated at 12% CO_2. The district calculated the maximum grain loading to be 0.002 grains per dry standard cubic foot for the gas turbines and 0.008 grains per dry standard cubic foot for the black-start engine, in compliance with the requirements of this rule.

Rule 62 – Sulfur Content of Fuels

This rule requires the sulfur content of gaseous fuels to contain no more than 10 grains of sulfur compounds, calculated as hydrogen sulfide, per 100 cubic feet of dry gaseous fuel (0.23 grams of sulfur compounds, calculated as hydrogen sulfide, per cubic meter of dry gaseous fuel), at standard conditions.

The PDOC did not specifically identify compliance with this rule, but the use of pipeline-quality natural gas would ensure compliance with this rule.

Rule 69.3 – Stationary Gas Turbines - Reasonably Available Control Technology

This rule limits NOx emissions from gas turbines greater than 0.3 MW to 42 ppm at 15% oxygen when fired on natural gas. The rule also specifies monitoring and record-keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits.

The PDOC notes that compliance with this rule is expected. This rule’s emission limits are less stringent than the BACT/LAER requirement of Rule 20.3(d)(1) for normal operation.

Rule 69.3.1 – Stationary Gas Turbines - Best Available Retrofit Control Technology

This rule limits NOx emissions from existing and new gas turbines greater than 10 MW to 15 x (E/25) ppm when operating uncontrolled and 9 x (E/25) ppm at 15% oxygen when operating with controls and averaged over a one-hour period (where E is the percent thermal efficiency of the unit, typically between 30–40% for gas turbines). The NOx emission limit consistent with the thermal efficiency for the OGP (37%) is 22.2 ppmv and 13.3 ppmv for uncontrolled and controlled operations, respectively. The rule also specifies monitoring and record-keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits. The District has also adopted a policy of 200 hours for initial commissioning when the standards of this rule do not apply.

The PDOC notes that compliance with this rule is expected. This rule’s emission limits are less stringent than the BACT/LAER requirement of Rule 20.3(d)(1) for normal operation.

Rule 69.4.1 – Stationary Reciprocating Internal Combustion Engines – Best Available Retrofit Control Technology

This rule limits emissions of NOx, CO, and VOC, and also has maintenance and recordkeeping requirements. NOx emissions are limited to 6.9 grams/bhp-hr, where the black-start engine has an emission guarantee of 1.5 grams/bhp-hr and the fire pump engine has an emission guarantee of 3.84 grams/bhp-hr. CO emission are limited to 4500 ppmv at 15% oxygen, where the black-start engine emissions are calculated to be 314 ppmv and the fire pump engine emissions are calculated to be 107 ppmv. VOC emissions from rich burn engines (only applicable to the black-start engine) are limited to 250 ppmv at 15% oxygen, where the black-start engine emissions are calculated to be 38 ppmv. Therefore, compliance with this rule is expected. This rule also exempts emergency engines from periodic source testing.

Regulation X – Standards of Performance for New Stationary Sources

This regulation adopts federal New Source Performance Standards (NSPS, 40 CFR Part 60) by reference. The relevant NSPS for the OGP, Subpart KKKK – Gas Turbines, has not been formally delegated for enforcement to SDAPCD; however, it is expected to be delegated later this year. This rule's emission limits are less stringent than the BACT/LAER requirement of Rule 20.3(d)(1) for normal operation. At the time of delegation the District would ensure compliance with the record-keeping requirements of this regulation.

Regulation XI – National Emission Standards for Hazardous Air Pollutants

This regulation adopts federal standards for hazardous air pollutants (HAPs) by reference. No such standards presently exist that would apply to the project due to the project's not being a major source of HAPs emissions.

Regulation XII – Toxic Air Contaminants

Rule 1200 – Toxic Air Contaminants, New Source Review

This rule requires a health risk estimate for sources of toxic air contaminants. Toxics Best Available Control Technology (TBACT) must be installed if a Health Risk Assessment shows an incremental cancer risk greater than one in a million, and no source would be allowed to cause an incremental cancer risk exceeding ten in a million. The District found that the project complied with the requirements of this rule.

Regulation XIV – Title V Operating Permits

Rule 1401 – General Provisions

This regulation contains the requirements for federal Title V Operating Permits. The applicant is required to submit for a revised Title V Operating Permit application within twelve months of initial startup of the project.

Rule 1412 – Federal Acid Rain Program Requirements

This regulation contains the requirements for participation in the federal Acid Rain Program. The applicant is required to submit an Acid Rain Program application to the District prior to commencement of operation.

NOTEWORTHY PUBLIC BENEFITS

No air quality related noteworthy public benefits have been identified.

CONCLUSIONS

The OGP would likely comply with all laws, ordinances, regulations, and standards and would result in a less than significant impact under CEQA if OGP complies with all staff-recommended and District-required conditions of certification and provides the emission offsets, in quantities recommended by staff in Condition of Certification **AQ-SC6**.

Staff has considered the minority population surrounding the site (see **Socioeconomics Figure 1**). Since the project's direct and cumulative air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

Staff has proposed a number of permit conditions that are in addition to the permit conditions that the SDAPCD has proposed. In most cases the staff-proposed permit conditions deal with air quality issues that the SDAPCD is not required to address. The staff-proposed conditions of certification are summarized as follows. Conditions of Certification **AQ-SC1** through **AQ-SC5** are construction-related permit conditions. **AQ-SC6** formalizes applicant' stipulation to staff's proposal to provide emission reductions for the project's emission increase on a 1:1 ratio for nonattainment pollutants and their precursors. **AQ-SC7** provides the administrative procedure requirements for project modifications. **AQ-SC8** limits concurrent uncontrolled initial commissioning operation for the two turbines and limits such operation to occur only from 7 am to 7 pm as both assumed and stipulated by the applicant. **AQ-SC9** and **AQ-SC10** provides the chiller cooling tower mist eliminator performance standard and requires the applicant to conduct cooling tower water testing and provide emission reporting that is not required in the SDAPCD conditions, respectively. **AQ-SC11** is a quarterly compliance report requirement. **AQ-SC12** requires new water delivery trucks or trucks with new engines that are maintained properly to minimize water trucking emissions.

Conditions of Certification **AQ-1** through **AQ-93** are the SDAPCD permit conditions with staff proposed verification language.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in AIR APPENDIX A. The Orange Grove Project, as a peaking project with an enforceable operating limitation less than 60% of capacity, is not subject to the requirements of SB1368 and the Emission Performance Standard. Staff recommends reporting of the GHG emissions as the Air Resources Board develops greenhouse gas regulations and/or trading markets (see Condition of Certification

GHG-1 in AIR APPENDIX A). The project may be subject to additional reporting requirements and GHG reduction or trading requirements as these regulations become more fully developed and implemented.

PROPOSED CONDITIONS OF CERTIFICATION

Staff recommends the following conditions of certification to address the impacts associated with the construction and operation of the OGP project. These conditions include the SDAPCD proposed conditions from the PDOC, with appropriate staff proposed verification language for each condition, as well as Energy Commission staff proposed conditions. Revisions to the conditions provided in the District's FDOC, which should be published sometime in November 2008, will be incorporated in the Commission's Staff Assessment Addendum.

STAFF CONDITIONS

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with conditions AQ-SC3, AQ-SC4, and AQ-SC5 for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site and linear facilities and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the Compliance Project Manager (CPM).

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates. The AQCMM and all Delegates must be approved by the CPM before the start of ground disturbance.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with conditions **AQ-SC3**, **AQ-SC4**, and **AQ-SC5**.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. The AQCMP must be approved by the CPM before the start of ground disturbance.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report (MCR) that demonstrates compliance with the following mitigation measures for the purposes of preventing all fugitive dust plumes from leaving the project site and linear facility routes. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

1. All unpaved roads and disturbed areas in the project and laydown construction sites shall be watered as frequently as necessary to comply with the dust mitigation objectives of AQ-SC4. The frequency of watering may be reduced or eliminated during periods of precipitation.

2. No vehicle shall exceed 10 miles per hour on unpaved areas within the project and laydown construction sites.

3. The construction site entrances shall be posted with visible speed limit signs.

4. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned and free of dirt prior to entering paved roadways.

5. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

6. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

7. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

8. Construction areas adjacent to any paved roadway shall be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent runoff to roadways.

9. All paved roads within the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

10. At least the first 500 feet of any public roadway exiting the construction site shall be swept visually clean, using wet sweepers or air filtered dry vacuum sweepers, at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff from the construction site is visible on the public roadways.

11. All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered or shall be treated with appropriate dust suppressant compounds.

12. All vehicles that are used to transport solid bulk material on public roadways and that have the potential to cause visible emissions shall be provided with a cover or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least two feet of freeboard.

13. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

14. Disturbed areas will be re-vegetated as soon as practical.

The fugitive dust requirements listed in this condition may be replaced with as stringent or more stringent methods as required by SDAPCD Rule 55 if that rule becomes effective prior to the completion of the project's construction activities.

Verification: The project owner shall include in the MCR (1) a summary of all actions taken to maintain compliance with this condition, (2) copies of any complaints filed with the air district in relation to project construction, and (3) any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported (1) off the project site or (2) 200 feet beyond the centerline of the construction of linear facilities, or (3) within 100 feet upwind of any regularly occupied structures not owned by the project owner indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression if Step 1 specified above fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if Step 2 specified above fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shut-down source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified.

AQ-SC5 Diesel-Fueled Engines Control: The AQCMM shall submit to the CPM, in the MCR, a construction mitigation report that demonstrates compliance with the following mitigation measures for the purposes of controlling diesel construction-related emissions. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

A. All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur.

B. All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

C. A good faith effort shall be made to find and use off-road construction diesel equipment that has a rating of 100 hp to 750 hp and that meets the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines as specified in Title 13, California Code of Regulations section 2423(b)(1). This good faith effort shall be documented with signed written correspondence by the appropriate construction contractors along with documented correspondence with at least two construction equipment rental firms.

D. All construction diesel engines, which have a rating of 50 hp or more, shall meet, at a minimum, the Tier 2 California Emission Standards for Off-Road Compression-Ignition Engines as specified in Title 13, California Code of Regulations section 2423(b)(1). The following exceptions for specific construction equipment items may be made on a case-by-case basis.

1. Tier 1 equipment will be allowed on a case-by-case basis only when the project owner has documented that no Tier 2 equipment is available for a particular equipment type that must be used to complete the project’s construction. This shall be documented with signed written correspondence by the appropriate construction contractors along with documented correspondence with at least two construction equipment rental firms.

2. The construction equipment item is intended to be on site for five days or less.

3. Equipment owned by specialty subcontractors may be granted an exemption, for single equipment items on a case-by-case basis, if it

can be demonstrated that extreme financial hardship would occur if the specialty subcontractor had to rent replacement equipment, or if it can be demonstrated that a specialized equipment item is not available by rental.

E. All heavy earthmoving equipment and heavy duty construction-related trucks with engines meeting the requirements of (c) above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

F. All diesel heavy construction equipment shall not remain running at idle for more than five minutes, to the extent practical.

G. Construction equipment will employ electric motors when feasible.

Verification: The project owner shall include in the MCR (1) a summary of all actions taken to maintain compliance with this condition, (2) copies of all diesel fuel purchase records, (3) a list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained, and (4) any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC6 The project owner shall provide emission reduction mitigation to offset the project's NOx, PM10, SOx, and VOC emission increases at a ratio of 1:1. These emission reductions are based on the following maximum annual emissions for the facility (tons/yr).

Emission Reduction Credits/Pollutant	**Tons/yr**
NOx	6.86
PM10	3.76
SOx	0.40
VOC	1.70
Total Tons	12.72

Emission reductions can be provided in any one of the following methods in the following order of preference of their use:

1. The project owner can fund emission reductions through the Carl Moyer Fund in the amount of $16,000/ton, or final 2008 ARB Carl Moyer Program Guideline cost effectiveness cap value, for the total ton quantity listed in the above table, minus any tons offset using the other two listed methods, with an additional 20% administration fee to fund the SDAPCD and/or other responsible local agencies with jurisdiction within 25 miles of the project site to be used to find and fund local emission reduction projects to the extent feasible. Emission reduction projects funding by this method will be weighted for evaluation and selection, within the funding guideline value of $16,000/ton of reduction, based on the proximity of the emission

reduction project and the relative health benefit to the local community surrounding the project site. Emission reduction project cost will not be a consideration for selection as long as the emission reduction project is within the proposed or approved 2008, or other year as applicable, Carl Moyer funding guideline value,

2. The project owner can fund other existing public agency regulated stationary or mobile source emission reduction programs or create a project specific fund to be administered through the SDAPCD or other local agency, which would provide surplus emission reductions. This funding shall include appropriate administrative fees as determined by the administering agency to obtain local emission reductions to the extent feasible. The project owner shall be responsible for demonstrating that the amount of such funding meets the emission reduction requirements of this condition. Emission reduction projects funding by this method will be weighted for evaluation and selection based on the proximity of the emission reduction project and the relative health benefit to the local community surrounding the project site.

3. ERC certificates from emission reductions occurring in the San Diego Air Basin can be used to offset each pollutant on a 1:1 offset ratio basis only if local emission reduction projects are clearly demonstrated to be unavailable using methods 1 or 2 to meet the total emission reduction burden required by this condition. ERCs can be used on an interpollutant basis for SOx for PM10, NOx for VOC, and VOC for NOx, where the project owner will provide a letter from the SDAPCD that indicates the District's allowed interpollutant offset ratio, or PM10 for SOx ERCs can be used on a 1:1 basis.

Carl Moyer or other emission reduction funding shall be provided to the responsible agencies prior to the initiation of on-site construction activities. The project owner shall work with the appropriate agencies to target emission reduction projects in the project area to the extent feasible. Emission reduction project selection information will be provided to the CPM for review and comment. Unused administrative fees shall be used for additional emission reduction program funding. ERC certificates, if used, will be surrendered prior to first turbine fire.

Verification: The project owner shall submit to the CPM confirmation that the appropriate quantity of Carl Moyer Project or other emission reduction program funding and/or ERCs have been provided prior to initiation of on-site construction activities for emission reduction program funding and at least 30 days prior turbine first fire for ERCs. The project owner shall provide emission reduction project selection information to the CPM for review and comment at least 15 days prior to committing funds to each selected emission reduction project. The project owner shall provide confirmation that the level of emission reduction program funding will meet the emission reduction requirements of this condition.

AQ-SC7 The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. EPA, and any revised permit issued by the District or U.S. EPA, for the project.

<u>Verification:</u> The project owner shall submit any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-SC8 The project owner shall only fire the CTGs during initial commissioning, when operating without fully functioning emission controls (SCR and oxidation catalyst), between the hours starting at 7 am ending at 7 pm.

<u>Verification:</u> The project owner shall submit to the CPM in the MCR the actual turbine initial commissioning hourly records while operating without fully functioning pollution controls (SCR and oxidation catalyst).

AQ-SC9 The chiller cooling tower shall have a mist eliminator with a manufacturer guaranteed mist reduction rate of 0.001% or less of the water recirculation rate.

<u>Verification:</u> The project owner shall provide the CPM a copy of the manufacturer guarantee for the mist eliminator 30 days prior to installation of the chiller.

AQ-SC10 The chiller cooling tower water shall be tested for total dissolved solids and that data shall be used to determine and report the particulate matter emissions from the chiller cooling tower. The cooling tower water shall be tested at least once annually during the anticipated summer operation peak period (July through September).

<u>Verification:</u> The project owner shall provide the water quality test results and the chiller cooling tower emissions estimates to the CPM as part of the fourth quarter's quarterly operational report (AQ-SC11).

AQ-SC11 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification herein. The Quarterly Operation Report will specifically note or highlight incidences of noncompliance.

<u>Verification:</u> The project owner shall submit the Quarterly Operation Reports to the CPM and to the District, if requested, no later than 30 days following the end of each calendar quarter.

AQ-SC12 The project owner shall procure the latest model year water delivery trucks, or trucks retrofit with new model year engines, that meet California on-road vehicle emission standards; and the water delivery trucks shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

<u>Verification:</u> The project owner shall submit to the CPM information on the procured water delivery trucks that show compliance with this condition within 15 days of procuring the trucks. The project owner shall submit truck maintenance records for the year in the fourth quarter Quarterly Operation Reports (AQ-SC11) that show compliance with the maintenance provision of this condition.

DISTRICT PRELIMINARY DETERMINATION OF COMPLIANCE CONDITIONS (SDAPCD 2008C)

985708

Gas Turbine Engine Generator #1: General Electric, Model LM-6000 PC SPRINT, 49.8 MW capacity, 468.8 MMBtu/hr heat input, natural gas fired, simple cycle, with water injection; a selective catalytic reduction (SCR) system including an automatic ammonia injection control system; an oxidation catalyst; a Continuous Emission Monitoring System (CEMS) for NOx, CO, and O_2; a data acquisition and handling system (DAHS); and remote data collection node (RDCN).

985709

Gas Turbine Engine Generator #1: General Electric, Model LM-6000 PC SPRINT, 49.8 MW capacity, 468.8 MMBtu/hr heat input, natural gas fired, simple cycle, with water injection; a selective catalytic reduction (SCR) system including an automatic ammonia injection control system; an oxidation catalyst; a Continuous Emission Monitoring System (CEMS) for NOx, CO, and O_2; a data acquisition and handling system (DAHS); and remote data collection node (RDCN).

General Conditions

AQ-1 This equipment shall be properly maintained and kept in good operating condition at all times.

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-2 The project owner shall operate the project in accordance with all data and specifications submitted with the application.

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-3 Access, facilities, utilities, and any necessary safety equipment for source testing and inspections shall be provided upon request of the Air Pollution Control District.

Verification: The project owner shall provide facilities, utilities, and safety equipment for source testing and inspections upon request of the District, ARB, and the Energy Commission.

AQ-4 The project owner shall obtain any necessary District permits for all ancillary combustion equipment including emergency engines, prior to on-site delivery of the equipment.

Verification: The project owner shall submit any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-5 The exhaust stacks for the combustion turbine shall be at least 80 feet in height above site base elevation.

Verification: The project owner shall submit to the CPM for review the exhaust stack specification at least 60 days before the installation of the stack.

AQ-6 This equipment shall be fired on Public Utility Commission (PUC) quality natural gas only. The project owner shall maintain quarterly records of sulfur content (grains/100 dscf) and higher and lower heating values (Btu/dscf) of the natural gas and provide such records to District personnel upon request.

Verification: The project owner shall submit the quarterly fuel sulfur content values in the in the Quarterly Operation Reports (**AQ-SC11**) and make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-7 The project owner shall submit a complete Acid Rain Permit application prior to commencement of operation in accordance with Title 40 Code of Federal Regulations Part 72 to the District and submit a copy to U.S. EPA, Region IX.

Verification: The project owner shall submit to the CPM copies of the acid rain permit application within five working days of its submittal by the project owner to the District.

AQ-8 The project owner shall submit an application to the District for a Federal (Title V) Operating Permit, in accordance with District Regulation XIV within 12 months after initial startup of this equipment.

Verification: The project owner shall submit to the CPM copies of the Title V operating permit application within five working days of its submittal by the project owner to the District.

AQ-9 The project owner shall comply with all applicable provisions of 40 CFR 73, including requirements to offset, hold and retire SO_2 allowances.

Verification: The project owner shall submit to the CPM and District the CTG annual operating data and SO2 allowance information demonstrating compliance with all applicable provisions of 40 CFR 73 as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-10 The total combined unit operating hours for the combustion turbines of Permit No. 985708 and 985711 shall not exceed 6,400 hours per calendar year. Unit operating hour is defined in 40CFR 72.2. (NSR).

Verification: The project owner shall submit to the CPM and District the CTG annual operating data demonstrating compliance with this condition as part of the fourth quarter’s Quarterly Operation Reports (**AQ-SC11**).

AQ-11 Operation of each turbine under startup and shutdown conditions shall not exceed 200 hours per year.

Verification: The project owner shall submit to the CPM and District the CTG startup and shutdown operating data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Reports (**AQ-SC11**).

AQ-12 The project owner shall comply with the applicable requirements in 40 CFR Parts 60, 72, 73, and 75.

Verification: The project owner shall submit to the CPM and District the CTG annual operating data demonstrating compliance with all applicable provisions of 40 CFR Parts 60, 72, 73, and 75 as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-13 Power output (net MW) from each turbine generator of Permit No. 985708 and 985711 to the grid shall not exceed 49.8 MW. (NSR).

Verification: The project owner shall submit to the CPM and District the CTG net power data demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

Emission Limits

AQ-14 For purposes of determining compliance based on source testing, the average of three subtests shall be used. For purposes of determining compliance with emission limits based on the CEMS, data collected in accordance with the CEMS protocol shall be used and averaging periods shall be as specified herein.

Verification: The project owner shall provide the annual source test data to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**), due in the quarter after the each year's source test report is completed. The project owner shall submit to the CPM for review and the District for approval a CEMS operating protocol at least 60 days prior to the operation the CEMS.

AQ-15 For each emission limit expressed as pounds per hour or parts per million based on a one-hour averaging period, compliance shall be based on each rolling continuous one-hour period using continuous emission data collected at least once every 15 minutes.

Verification: CEMS data summaries shall be submitted to the CPM as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-16 During startup, the emissions from each turbine shall not exceed the following emission limits as determined by the continuous emission monitoring system

(CEMs), continuous monitor and/or District-approved emission testing. Compliance with each limit shall be based on a 1-hour averaging period.

Pollutant	Limit, lbs/hour
Oxides of Nitrogen (NOx), calculated as NO2	20.9
Carbon Monoxide (CO)	19.6
Volatile Organic Compounds (VOC)	3.3

<u>Verification:</u> The project owner shall submit to the CPM the CTG operating data demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-17 During shutdown, the emissions from each turbine shall not exceed the following emission limits as determined by the continuous emission monitoring system (CEMs), continuous monitor and/or District-approved emission testing. Compliance with each limit shall be based on a 1-hour averaging period

Pollutant	Limit, lbs/hour
Oxides of Nitrogen (NOx), calculated as NO2	16.5
Carbon Monoxide (CO)	27.8
Volatile Organic Compounds (VOC)	4.5

<u>Verification:</u> The project owner shall submit to the CPM the CTG operating data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC11**).

AQ-18 The emissions concentration of oxides of Nitrogen (NOx), calculated as nitrogen dioxide (NO_2), shall not exceed 2.5 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen and averaged over one hour period. Compliance with these limits shall be demonstrated continuously based on the CEMs data and at the time of the initial source test calculated as the average of three subtests. This limit shall not apply during the initial commissioning period or startup and shutdown periods as defined herein.

<u>Verification:</u> The project owner shall provide the source test data to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**), due in the quarter after the source test report is completed. The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-19 The emissions concentration of CO from the unit exhaust stack shall not exceed 6 parts per million volume on a dry basis (ppmvd) corrected to15% oxygen and averaged over one hour period. Compliance with this limit shall be demonstrated at the time of the initial source test and continuously based on the CEMs data and based upon source testing calculated as the average of three subtests. This limit shall not apply during the initial commissioning period or startup and shutdown periods.

<u>Verification:</u> The project owner shall provide the source test data to demonstrate compliance with this condition as part of the Quarterly Operation Report (**AQ-SC11**), due in the quarter after the source test report is completed. The project owner shall provide emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-20 The VOC concentration, calculated as methane, measured in the exhaust stack, shall not exceed 2.0 ppmvd corrected to 15% oxygen. Compliance with this limit shall be demonstrated by source testing, calculated as the average of three subtests. This limit shall not apply during the initial commissioning period or startup and shutdown periods.

<u>Verification:</u> The project owner shall provide the source test data to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**), due in the quarter after the source test report is completed.

AQ-21 The emissions from each turbine shall not exceed the following emission limits, except during the initial commissioning period, startup and shutdown conditions, as determined by the continuous emission monitoring system (CEMs), continuous monitor and/or District-approved emission testing, calculated as the average of three subtests. Compliance with each limit shall be based on a 1-hour averaging period.

Pollutant	Limit, lbs/hour
Oxides of Nitrogen (NOx), calculated as NO2	4.3
Carbon Monoxide (CO)	6.1
Volatile Organic Compounds (VOC)	1.3

<u>Verification:</u> The project owner shall submit to the CPM the CTG operating and/or source test data demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC11).

AQ-22 The emissions from each turbine shall not exceed the following emission limits, except during the initial commissioning period, as determined by the continuous emission monitoring system (CEMs), continuous monitor and/or District-approved emission testing, calculated as the average of three subtests. Compliance with each limit shall be based on a 1-hour averaging period.

Pollutant	Limit, lbs/day
Oxides of Nitrogen (NOx), calculated as NO2	137.1
Carbon Monoxide (CO)	179.9
Volatile Organic Compounds (VOC)	35.4

<u>Verification:</u> The project owner shall submit to the CPM the CTG operating data demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-23 The emissions from each turbine shall not exceed the following emission limits, except during the initial commissioning period, as determined by the continuous emission monitoring system (CEMs), continuous monitor and/or District-approved emission testing, calculated as the average of three subtests. Compliance with each limit shall be based on a 1-hour averaging period.

Pollutant	Limit, tons/year
Oxides of Nitrogen (NOx), calculated as NO_2	8.5
Carbon Monoxide (CO)	11.3
Volatile Organic Compounds (VOC)	2.2

Verification: The project owner shall submit to the CPM the CTG operating data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Reports (**AQ-SC11**).

AQ-24 Emissions of particulate matter less than 10 microns (PM10) shall not exceed 3.0 lbs per hour. Compliance with this limit shall be demonstrated based upon source testing calculated as the average of three subtests.

Verification: The project owner shall provide the source test data to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**), due in the quarter after the source test report is completed.

AQ-25 Ammonia emissions from each turbine shall not exceed 5 parts per million volume on a dry basis (ppmvd) corrected to 15% oxygen. This limit shall not apply during the commissioning period or startup and shutdown periods Compliance with this limit shall be demonstrated through source testing calculated as the average of three subtests and utilizing one of the following procedures:

1. Calculate daily ammonia emissions using the following equation:
   NH_3 = ((a-(b*c/1,000,000))*(1,000,000/b))*d
   Where:

   a = ammonia injection rate (lbs/hour) / (17.0 lbs/lb-mole),

   b = exhaust flow rate at 15% oxygen / (29 lbs/lb-mole)

   c = change in measured NOx concentration (ppmvd @ 15% oxygen) across the catalyst,

   d = ratio of measured ammonia slip to calculate ammonia slip as derived during compliance testing.

2. Other calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @15% oxygen, as approved by the District.

Verification: The project owner shall provide the estimated daily ammonia concentration and daily ammonia emissions based on the procedures given in this condition and provide the annual source test data to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**), where the source test data is due in the quarter after the source test report is completed.

AQ-26 When operating without SCR or oxidation catalyst during the initial commissioning period, the emissions from the turbine shall not exceed 50 pounds per hour of oxides of nitrogen (NOx), calculated as nitrogen dioxide and measured over each clock hour period. (Rule 20.3(d)(2)(i)).

Verification: The project owner shall submit to the CPM the CTG operating and CEMS data demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-27 When operating without SCR or oxidation catalyst during the initial commissioning period, the total emissions from the turbine shall not exceed 43.9 pounds per hour of carbon monoxide (CO), measured over each clock hour period. (Rule 23(d)(2)(i))

Verification: The project owner shall submit to the CPM the CTG operating and CEMS data demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-28 Visible emissions from the lube oil vents and the exhaust stack of the unit shall not exceed 20% opacity for more than three (3) minutes in any period of 60 consecutive minutes. (Rule 50)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-29 Total aggregate emissions from all stationary emission units at this stationary source, except emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1), shall not exceed the following limits in each rolling 12-calendar month period. The total aggregate emissions shall include emissions during all times that the equipment is operating, including but not limited to, emissions during periods of commissioning, startup, shutdown, and tuning.

1. Oxides of Nitrogen (NOx): 50 tons/year
2. Carbon Monoxide (CO): 100 tons/year
3. Volatile Organic Compounds (VOC): 50 tons/year
4. Oxides of Sulfur (SOx): 100 tons/year

Verification: The project owner shall submit to the CPM and District the facility annual operating and emissions data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Reports **(AQ-SC11).**

AQ-30 The emissions of any single federal Hazardous Air Pollutant (HAP) shall not equal or exceed 10 tons, and the aggregate emissions of all federal HAPs shall not equal or exceed 25 tons in any rolling 12-calendar month period. Compliance with these single and aggregate HAP limits shall be based on a methodology approved by the District for the purpose of calculating HAP emissions for this permit. If emissions exceed these limits, the project owner shall apply to amend permit to reflect applicable federal Maximum Achievable Control Technology (MACT) standards and requirements in accordance with applicable provisions (including timing requirements) of 40 CFR Part 63.

Verification: The project owner shall submit to the CPM and District the facility annual operating data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Reports **(AQ-SC11).**

Ammonia - SCR

AQ-31 At least 90 days prior to the start of construction, the project owner shall submit to the District the final selection, design parameters and details of the selective catalytic reduction (SCR) and oxidation catalyst emission control systems. Such information may be submitted to the District as trade secret and confidential pursuant to District Rules 175 and 176.

Verification: The project owner shall submit to the CPM for review and District for approval final selection, design parameters and details of the SCR and oxidation catalyst emission control systems at least 90 days prior to the start of construction.

AQ-32 Before operating an SCR system, continuous monitors shall be installed on each SCR system to monitor or calculate, and record the ammonia injection rate (lbs/hour) and the SCR catalyst temperature (°F). The monitors shall be installed, calibrated and maintained in accordance with a District approved protocol. This protocol, which shall include the calculation methodology, shall be submitted to the District for written approval at least 60 days prior to initial startup of the gas turbines with the SCR system. The monitors shall be in full operation at all times when the turbine is in operation.

Verification: The project owner shall provide a protocol as required in the condition for the installation, calibration, and testing for the SCR system continuous monitors at least 60 days prior to SCR system use. The project owner shall submit to the CPM and District the SCR system operating data demonstrating compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC11).**

AQ-33 Except during periods when the ammonia injection system is being tuned or one or more ammonia injection systems is in manual control (for compliance with applicable permits), the automatic ammonia injection system serving the SCR shall be in operation in accordance with manufacturer's specifications at all times when ammonia is being injected into the SCR. Manufacturer specifications shall be maintained on site and made available to district personnel upon request.

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-34 The concentration of ammonia solution used in the ammonia injection system shall be less than 20% ammonia by weight. Records of ammonia solution concentration shall be maintained on site and made available to district personnel upon request.

Verification: The project owner shall maintain on site and provide on request of the CPM or District the ammonia delivery records that demonstrate compliance with this condition.

Definitions

AQ-35 For the purposes of this Authority to Construct, startup conditions shall be defined as the time fuel flow begins until the time that the unit complies with the emission limits specified in this Authority to Construct but in no case exceeding 30 minutes per occurrence. Shutdown conditions shall be defined as the time preceding the moment at which fuel flow ceases and during which the unit does not comply with the emission limits specified in this Authority to Construct but in no cases exceeding 30 minutes per occurrence. The Data Acquisition and Recording System (DAS), as required by 40 CFR75, shall record these events. This condition may be modified by the District based on field performance of the equipment.

Verification: The project owner shall submit to the CPM the CTG start-up and shut-down event duration data demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

AQ-36 A CEMS protocol is a document approved in writing by the APCD M&TS division that describes the Quality Assurance and Quality Control procedures for monitoring, calculating and recording stack emissions from the unit.

Verification: The project owner shall maintain a copy of the CEMS protocol on site and provide it for inspection on request of the CPM or District.

AQ-37 Tuning is defined as adjustments to the combustion system that involves operating the unit in a manner such that the emissions control equipment may not be fully effective or operational. Only one gas turbine will be tuned at any given time. Tuning events shall not exceed 480 minutes in a calendar day nor exceed 40 hours in a calendar year. The District compliance division shall be notified at least 24 hours in advance of any tuning event.

Verification: The project owner shall notify the District and CPM at least 24 hours in advance of any tuning event. The project owner shall submit to the CPM the CTG operating data demonstrating compliance with tuning limitations identified in this condition as part of the Quarterly Operation Reports (**AQ-SC11**).

Testing

AQ-38 The project owner shall submit the proposed protocol for the source test 60 days prior to the proposed source test date to the District for approval. The project owner shall notify the District no later than 45 days prior to the proposed source test date and time.

Verification: The project owner shall submit to the CPM for review and the District for approval the initial source test protocol at least 60 days prior to the initial source test. The project owner shall notify the CPM and District no later than 45 days prior to the proposed source test date and time.

AQ-39 At least 60 days prior to initial startup of the gas turbines, the project owner shall submit a source test protocol to the District for approval. The source test protocol shall comply with the following requirements:

A. Measurements of NOX, CO, and O2 emissions shall be conducted in accordance with U.S. Environmental Protection Agency (U.S. EPA) methods 7E, 10, and 3A, respectively, and district Source Test, method 100, or alternative methods approved by the District and U.S. EPA;

B. Measurement of VOC emissions shall be conducted in accordance with U.S. EPA Methods 25A and/or 18, or alternative methods approved by the District and U.S. EPA;

C. Measurements of PM-10 emissions shall be conducted in accordance with U.S. EPA Methods 201A and 202 or alternative methods approved by the district and U.S. EPA;

D. Measurements of ammonia emissions shall be conducted in accordance with Bay Area Air Quality Management District ST-1B or an alternative method approved by the District and U.S. EPA;

E. Source testing shall be performed at the most frequently used load level, as specified in 40 CFR part 75 Appendix A Section 6.52.1.d, provided it is not less than 80% of the unit's rated load unless it is demonstrated to the satisfaction of the district that the unit cannot operate under these conditions . If the demonstration is accepted, then emissions source testing shall be performed at the highest achievable continuous level power level.

F. Measurements of opacity shall be conducted in accordance with U.S. EPA Method 9 or an alternative method approved by the District and U.S. EPA

G. Measurement of fuel flow shall be conducted in accordance with an approved test protocol.

Verification: The project owner shall submit to the CPM for review and the District for approval the initial source test protocol in compliance with requirements of this condition at least 60 days prior to the initial source test.

AQ-40 Each turbine shall be equipped with continuous monitors to measure or calculate, and record, the following operational characteristics of each unit:

1. Hours of operation (hours),

2. Natural gas flow rate (scfh),

3. Heat input rate (MMBtu /hr),

4. Exhaust gas flow rate (dscfm),

5. Exhaust gas temperature (ºF), and

6. Power output (gross MW).

7. Water (for NOx control) injection rate (lbs/hour) if equipped with water injection.

Verification: The project owner shall submit to the CPM for review and the District for approval a parametric monitoring protocol in compliance with this condition at least 60 days prior to the initial startup.

AQ-41 At least 60 days prior to the initial startup of the gas turbines, the project owner shall submit a turbine operation monitoring protocol, which shall include relevant calculation methodologies to the District for written approval. The monitors shall be installed, calibrated, and maintained in accordance with the protocol. The monitors should be in full operation at all times when the turbine is in operation. Calibration records for the continuous monitors shall be maintained on site and made available to the district upon request. The project owner shall make the site available for inspection of the turbine operation monitors and monitor maintenance records by representatives of the District, ARB, and the Energy Commissions.

Verification: The project owner shall submit to the CPM for review and the District for approval a turbine operation monitoring protocol in compliance with this condition at least 60 days prior to the initial startup.

AQ-42 The exhaust stacks for each turbine shall be equipped with source test ports and platforms to allow for the measurement and collection of stack gas samples consistent with all approved test protocols. The ports and platforms shall be constructed in accordance with District Method 3A, Figure 2, and approved by the District.

Verification: The project owner shall submit to the CPM for review and District for approval a stack test port and platform plan at least 60 days before the installation of the stack ports and platform.

AQ-43 This unit shall be source tested to demonstrate compliance with the NOx, CO, VOC, and ammonia emission standards of this permit, using District approved methods. The source test and the NOx and CO Relative Accuracy

Test Audit (RATA) tests shall be conducted in accordance with the applicable RATA frequency requirements of 40 CFR75, appendix b, sections 2.3.1 and 2.3.3.

Verification: The results and field data collected during source tests required by this condition shall be submitted to the CPM for review and the District for approval within 60 days of testing.

AQ-44 A Relative Accuracy Test Audit (RATA) and all other required certification tests shall be performed and completed on the CEMS in accordance with applicable provisions of 40 CFR part 75 Appendix A and B performance specifications. At least 30 days prior to the test date, the project owner shall submit a test protocol to the District for approval. Additionally, the District shall be notified a minimum of 21 days prior to the test so that observers may be present.

Verification: The project owner shall submit to the CPM for review and the District for approval the RATA certification test protocol at least 30 days prior to the RATA test and shall notify the CPM and District of the RATA test date at least 21 days prior to conducting the RATA and other certification tests.

AQ-45 If source testing will be performed by an independent contractor and witnessed by the District, a source test protocol shall be submitted to the District for written approval at least 30 days prior to source testing.

Verification: The project owner shall submit to the CPM for review and District for approval, if necessary based on the condition requirements, a source test protocol at least 30 days prior to the source test.

AQ-46 Within 45 days after completion of the source test or RATA, a final test report shall be submitted to the District for review and approval.

Verification: The project owner will submit all RATA or source test reports to the CPM for review and the District for approval within 45 days of the completion of those tests.

Continuous Emission Monitoring System (CEMS)

AQ-47 The project owner shall comply with the continuous emission monitoring requirements of 40 CFR Part 75.

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS monitoring protocol at least 60 days prior to the operation the CEMS.

AQ-48 At least 60 days prior to initial startup of the gas turbines, the project owner shall submit a turbine monitoring protocol to the District for written approval. The project owner shall make the site available for inspection of the turbine operation monitors and monitor maintenance records by representatives of the District, ARB, and the Energy Commission.

Verification: The project owner shall submit to the CPM for review and the District for approval a turbine monitoring protocol in compliance with this condition at least 60 days prior to the initial startup.

AQ-49 At least 60 days prior to initial startup of the gas turbines, the project owner shall submit a protocol to the District, for written approval, that show how the permanent CEMs will be able to meet all District monitoring requirements and measure NOx emissions at a level of 2.5 ppmv.

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS operating protocol at least 60 days prior to the operation the CEMS.

AQ-50 At least 60 days prior to the operation of the permanent CEMs, the project owner shall submit a CEMs operating protocol to the District for written approval. The project owner shall make the site available for inspection of the CEMs and CEMs maintenance records by representatives of the District, ARB, and the Energy Commission.

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS operating protocol at least 60 days prior to the operation the permanent CEMS.

AQ-51 A monitoring plan in conformance with 40 CFR 75.53 shall be submitted to U.S. EPA Region 9 and the District at least 45 days prior to the Relative Accuracy Test Audit test, as required in 40 CFR 75.62.

Verification: The project owner shall submit to the CPM for review and the District for approval a monitoring plan in compliance with this condition at least 45 days prior to the RATA test.

AQ-52 No later than 90 days after each unit commences commercial operation (defined for this condition as the instance when power is sold to the grid), a Relative Accuracy Test Audit (RATA) and other required certification tests shall be performed an completed on the CEMs in accordance with 40 CFR Part 75 Appendix A Specifications and Test Procedures. At least 60 days prior to the test date, the project owner shall submit a test protocol to the District for written approval. Additionally, the District shall be notified a minimum of 45 days prior to the test so that observers may be present. Within 30 days of completion of this test, a written test report shall be submitted to the District for approval.

Verification: The project owner shall submit to the CPM for review and the District for approval the RATA certification test protocol at least 60 days prior to the RATA test and shall submit to the CPM for review and the District for approval a copy of the written test report within 30 days after test completion The project owner shall also notify the CPM and District of the RATA test date at least 45 days prior to conducting the RATA and other certification tests.

AQ-53 The oxides of nitrogen (NOX) and oxygen (O2) CEMS shall be certified and maintained in accordance with applicable Federal Regulations including the requirements of Sections 75.10 and 75.12 of Title 40, Code of Federal Regulations Part 75 (40 CFR 75), the performance specifications of Appendix A of 40 CFR 75, the quality assurance procedures of Appendix B of 40 CFR 75 and the CEMS protocol approved by the District. The carbon monoxide (CO) CEMS shall be certified and maintained in accordance with 40 CFR 60, Appendices B and F, unless otherwise specified in this permit, and the CEMS protocol approved by the District.

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS operating protocol as required by **AQ-50**. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-54 Continuous emission monitoring system (CEMS) shall be installed and properly maintained and calibrated to measure, calculate and record the following, in accordance with the District approved CEMS protocol:

A. Percent oxygen (O2) in the exhaust gas (%);

B. Average concentration of oxides of nitrogen (NOX) for each continuous rolling 3-hour period, in parts per million (ppmv) corrected to 15% oxygen;

C. Average concentration of carbon monoxide (CO) for each continuous rolling 3-hour period, in parts per million (ppmv) corrected to 15% oxygen;

D. Annual mass emissions of oxides of nitrogen (NOX), in tons;

E. Annual mass emission of carbon monoxide (CO), in tons.

F. Natural gas flow rate to turbine in hscf/hr.

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS operating protocol as required by **AQ-50**. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-55 The CEMS shall be in operation in accordance with the district approved CEMs monitoring protocol at all times when the turbine is in operation. A copy of the District approved CEMS monitoring protocol shall be maintained on site and made available to District personnel upon request.

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-56 When the CEMS is not recording data and the turbine is operating, hourly NOx emissions for the annual emission calculations shall be determined in accordance with 40 CFR 75 Subpart C. Additionally, hourly CO emissions for annual emission calculations shall be determined using CO emission factors to be determined from source test emission factors and fuel consumption data, in terms of pounds per hour of CO for the gas turbine. Emission calculations used to determine hourly emission rates shall be reviewed and approved by the District, in writing, before the hourly emission rates are incorporated into the CEMS emission data.

Verification: The project owner shall provide the District with all emission calculations required by this condition and shall provide notation of when such calculations are used in place of CEMS data as part of the Quarterly Operation Report (**AQ-SC11**).

AQ-57 Any violation of any emission standard as indicated by the CEMS shall be reported to the district's compliance division within 96 hours after such occurrence (H&S Code).

Verification: The project owner shall notify the District regarding any emission standard violation as required in this condition and shall document all such occurrences in each Quarterly Operation Report (**AQ-SC11**).

AQ-58 The CEMS shall be maintained and operated, and reports submitted, in accordance with the requirements of rule 19.2 Sections (d), (e), (f) (1), (f) (2), (f) (3), (f) (4) and (f) (5), and a CEMS protocol approved by the District. 24368

Verification: The project owner shall submit to the District the CEMS reports as required in this condition and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-59 An operating log or data acquisition and handling system (DAHS) records shall be maintained either on site or at a district-approved alternate location to record actual times and durations of all startups and shut-downs, quantity of fuel used (scf) and energy generated (MW-hr), (monthly and annually by calendar year), hours of daily operation and total cumulative hours of operation (monthly and annually by calendar year).

Verification: The operating log or DAHS operating records will be provided as part of the Quarterly Operation Report (**AQ-SC11**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-60 Except for changes that are specified in the initial approved NOx monitoring protocol or a subsequent revision to that protocol that is approved in advance, in writing by the District, the District shall be notified in writing at least thirty (30) days prior to any planned changes made in the CEMS /DAHS (including the programmable logic controller) software which affects the value of data displayed on the CEMS / DAHS monitors with respect to the parameters measured by their respective sensing devices or any planned changes to the software that controls the ammonia flow to the SCR. Unplanned or emergency changes shall be reported within 96 hours.

Verification: The project owner shall submit to the CPM for review and the District for approval any revision to the CEMS/DAHS software, as required by this condition, to be approved in advance at least 30 days before any planned changes are made.

AQ-61 Fuel flow meters with an accuracy of +/- 2% shall be maintained to measure the volumetric flow rate corrected for temperature and pressure. Correction factors and constants shall be maintained on site and made available to the district upon request. The fuel flow meters shall meet the applicable quality assurance requirements of 40 CFR part 75, Appendix D, and Section 2.1.6.

Verification: The project owner shall submit to the CPM the natural gas usage data from the fuel flow meters as part of the Quarterly Operation Report (**AQ-SC11**).

Commissioning

AQ-62 Beginning at initial startup of each turbine, a Commissioning Period for each turbine shall commence. The Commissioning Period shall end 120 days after initial startup or immediately after written acceptance of clear custody and control of the equipment is turned over to the project owner, or after not more than 200 hours of gas turbine operation whichever comes first. During the Commissioning Period, only the emission limits specified in conditions 63 and 64 shall apply.

Verification: A log of the dates, times, and cumulative unit operating hours when fuel is being combusted during the commissioning period shall be maintained by the project owner. The project owner shall submit, commencing one month from the time of gas turbine first fire, a monthly commissioning status report throughout the duration of the commissioning phase that demonstrates compliance with the requirements listed in this condition. The monthly commissioning status report shall be submitted to the CPM by the 10^{th} of each month for the previous month, for all months with turbine commissioning activities following the turbine first fire date. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-63 During the Commissioning Period when operating without SCR or oxidation catalyst, the total aggregate NOx emissions from the equipment described in applications # 985708 and 985711 combined shall not exceed 100 pounds per hour, calculated as nitrogen dioxide and measured over each 1-clock hour period. This emission limit shall apply during all times the turbine is operating, including, but not limited to emissions during periods of commissioning, startup, shutdown, low load operation and tuning.
(Rule 20.3(d)(2)(i))

Verification: The project owner shall provide the CPM CEMS data demonstrating compliance with this condition as part of the monthly commissioning status report (**AQ-62**).

AQ-64 During the Commissioning Period when operating without SCR or oxidation catalyst, the total aggregate CO emissions from the equipment described in applications # 985708 and 985711 combined shall not exceed 87.8 pounds per hour measured over each 1-clock hour period. This emission limit shall apply during all times that one or both turbines are operating, including, but not limited to emissions during periods of commissioning, startup, shutdown, low load operation and tuning. (Rule 20.3(d)(2)(i)).

Verification: The project owner shall provide the CPM CEMS data demonstrating compliance with this condition as part of the monthly commissioning status report (**AQ-62**).

AQ-65 Within 120 days or 200 hours of gas turbine operation, whichever comes first, after initial startup of each turbine, the project owner shall install post-combustion air pollution control equipment to minimize emissions from this equipment. Once installed, the post-combustion air pollution control equipment shall be maintained in good condition and, with the exception of periods during startup and shutdown, shall be in full operation at all times when the turbine is in stable operation.

Verification: The project owner shall provide the CPM District records demonstrating compliance with this condition as part of the monthly commissioning status report (**AQ-62**).

AQ-66 After the end of the Commissioning Period for each turbine, the project owner shall submit a written progress report to the District. This report shall include, a minimum, the date the Commissioning Period ended, the periods of startup, the emissions of NOx and CO during startup, and the emissions of NOx and CO during steady state operation. NOx and CO emissions shall be reported in both ppmv at 15% O2 and lbs/hour. This report shall also detail any turbine or emission control equipment malfunction, upset, repairs, maintenance, modifications, or replacements affecting emissions of air contaminants that occurred during the Commissioning Period.

Verification: The project owner shall provide the CPM and the District records demonstrating compliance with this condition as part of the final monthly commissioning status report (**AQ-62**).

AQ-67 Only one combustion turbine shall undergo commissioning at a time.

Verification: The project owner shall provide the CPM CEMS data demonstrating compliance with this condition as part of the monthly commissioning status report (**AQ-62**).

AQ-68 For the purpose of the Determination of Compliance and Authority to Construct, the period described as "on-going" operation of the turbines shall commence immediately following the end of the Commissioning Period. Conditions Numbers AQ-21 and AQ-22 shall continue to apply during on-going operations.

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-69 Within 30 days after completion of the Commissioning Period, an initial emission source test shall be conducted by an independent, ARB approved tester at the project owner's expense to show compliance with all applicable emission limits. A source test protocol shall be submitted to the District for written approval at least 60 days prior to source testing. The source test protocol shall comply with the following requirements:

A. Measurements of NOx and CO emission concentrations, and O2 concentration shall be conducted in accordance with U.S. Environmental Protection Agency (U.S. EPA) methods 7E, 10, and 3A, respectively, and district Source Test, method 100, or alternative methods approved by the District and U.S. EPA;

B. Measurement of VOC emissions shall be conducted in accordance with U.S. EPA Methods 25A and/or 18, or alternative methods approved by the District and U.S. EPA;

C. Measurement of PM-10 emissions shall be conducted in accordance with U.S. EPA Method 201A and 202 or alternative methods approved by the District and U.S. EPA;

D. Measurements of ammonia emissions shall be conducted in accordance with Bay Area Air Quality Management District ST-1B or an alternative method approved by the District and U.S. EPA;

E. To determine compliance with NOx, CO, particulate matter and ammonia concentrations or emission limits of the equipment on this application, source testing shall be performed at the most frequently used load level, as specified in 40 CFR part 75 Appendix A Section 6.52.1.d, provided it is not less than 80% of the unit's rated load unless it is demonstrated to the satisfaction of the district that the unit cannot operate under these conditions. If the demonstration is accepted, then emissions source testing shall be performed at the highest achievable continuous level power level.

F. Measurement of opacity shall be conducted in accordance with U.S. EPA Method 9 or an alternative method approved by the District and U.S. EPA.

G. Measurement of fuel flow shall be conducted in accordance with an approved test protocol.

Verification: The project owner shall submit to the CPM for review and the District for approval the initial source test protocol in compliance with requirements of this condition at least 60 days prior to the initial source test.

AQ-70 The project owner shall submit the proposed protocol for the source test 60 days prior to the proposed source test date to both the District for approval. The project owner shall notify the District no later than 45 days prior to the proposed source test date and time.

Verification: The project owner shall submit to the CPM for review and the District for approval the initial source test protocol in compliance with requirements of this condition at least 60 days prior to the initial source test. The project owner shall submit a completed source test date and time notification form to the District at least 45 days before the proposed test date.

985710

Gas 965 brake horsepower (bhp) Cummins GTA38-G2 natural gas fueled black start engine, with catalytic converter and air to fuel ratio controller, driving a 625 kilowatt (KW) generator.

AQ-71 Project owner shall provide access, facilities, utilities and any necessary safety equipment, with the exception of personal protective equipment requiring individual fitting and specialized training, for source testing and inspection upon request of the District.

Verification: The project owner shall provide facilities, utilities, and safety equipment for source testing and inspections upon request of the District, ARB, and the Energy Commission.

AQ-72 Gaseous fuel engines shall use only gaseous fuel which contains no more than 10 grains of sulfur compounds, calculated as hydrogen sulfide, per 100 cubic feet dry gaseous fuel at standards conditions. Gaseous fuels include natural gas, propane, liquefied petroleum gas (LPG), butane. Gasoline engines shall use only California Reformulated Gasoline. (Rule 62).

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-73 Visible emissions including crank case smoke shall comply with Rule 50. (Rule 50)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-74 At no time shall the subject equipment described cause or contribute to a public nuisance. (Rule 51)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-75 A non-resettable engine hour meter shall be installed on this engine, maintained in good working order, and used for recording engine operating hours. If a meter is replaced, the Air Pollution Control District’s Compliance Division shall be notified in writing within 10 calendar days. The written notification shall include the following information:

A. Old meter’s hour reading.

B. Replacement meter’s manufacturer name, model, and serial number if available and current hour reading on replacement meter.

C. Copy of receipt of new meter or of installation work order.

A copy of the meter replacement notification shall be maintained on site and made available to the Air Pollution Control District upon request.
(Rule 69.4.1.)

Verification: The project owner shall provide notification to the District as required by this condition and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-76 The engine operation shall not exceed 0.5 hours per day and 52 hours per calendar year for non-emergency purposes (testing and maintenance). (NSR, Rule 69.4.1)

Verification: The project owner shall submit to the CPM the black-start engine operating data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC11**).

AQ-77 The owner or operator shall conduct periodic maintenance of this engine and any add-on control equipment, as applicable, as recommended by the engine and control equipment manufacturer or as specified by any other maintenance procedure approved in writing in writing by the District. The periodic maintenance shall be conducted at least once each calendar year. (Rule 69.4.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-78 The owner or operator of the engine shall keep the following records: applicable fuel certification; manual of recommended maintenance provided by the manufacturer, or other maintenance procedure as approved in writing, in advance, by the District. These records shall be kept on site for at least the same period of time as the engine to which the records apply is located at the site. These records shall be made available to the District. (Rule 69.4.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-79 The owner or operator of this engine shall maintain an operating log containing, at a minimum, the following: dates and times of engine operation, indicating whether the operation was for non- emergency purposes or during an emergency situation and the nature of the emergency, if available (these records are not required if the total engine operations for any purpose, including emergency situation, do not exceed 52 hours in a calendar year); total cumulative hours of operation per calendar year, based on actual readings of engine hour meter or fuel meter; records of periodic maintenance including the dates maintenance, calibration or replacement were performed. (Rule 69.4.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-80 All operational and maintenance logs required by this permit shall be kept for a minimum of three years, unless otherwise indicated by the conditions of this permit, and these records shall be made available to the District upon request. (Rule 69.4.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

985711

373 bhp Cummins CFP11E-F10 diesel fueled emergency fire pump engine.

AQ-81 Project owner shall provide access, facilities, utilities and any necessary safety equipment, with the exception of personal protective equipment requiring individual fitting and specialized training, for source testing and inspection upon request of the District.

Verification: The project owner shall provide facilities, utilities, and safety equipment for source testing and inspections upon request of the District, ARB, and the Energy Commission.

AQ-82 Engine operation for maintenance and testing purposes shall not exceed 0.5 hour per day and 50 hours per calendar year. (NSR) (17 CCR §93115) (ATCM reportable)

Verification: The project owner shall submit to the CPM the fire pump engine operating data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC11**).

AQ-83 The engine shall only use ARB Diesel Fuel. (Rule 69.4.1, 17 CCR §93115)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-84 Visible emissions including crankcase smoke shall comply with Air Pollution Control District Rule 50. (Rule 50)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-85 The equipment described above shall not cause or contribute to public nuisance. (Rule 51)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-86 This engine shall not operate for non-emergency use during the following periods, as applicable:

A. Whenever there is any school sponsored activity, if engine is located on school grounds or

B. Between 7:30 and 3:30 PM on days when school is in session, if the engine is located within 500 feet of, but not on school grounds.

This condition shall not apply to an engine located at or near any school grounds that also serve as the student's place of residence (17 CCR §93115) (ATCM reportable).

Verification: The project owner shall submit to the CPM the engine operating data demonstrating compliance with this condition on request and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-87 Engine operation in response to notification of an impending rotating outage, shall be restricted to the following condition:

A. The utility distribution company has ordered rotating outages in the control area where he engine is located,

B. The engine is operated no more than 30 minutes prior to the time when the utility distribution company officially forecasts a rotating outage in the cited control area, and

C. The engine operation is terminated immediately after the utility distribution company advises that a rotating outage is no longer in effect.

This condition shall not apply to engines operating pursuant to the rolling blackout reduction program as identified in 17 CCR 93115 and operating in accordance with 17 CCR 93115 (e)(2)(f). (17 CCR 93115) (ATCM reportable).

Verification: The project owner shall submit to the CPM the engine operating data demonstrating compliance with this condition on request and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-88 A non-resettable engine hour meter shall be installed on this engine, maintained in good working order, and used for recording engine operating hours. If a meter is replaced, the Air Pollution Control District's Compliance Division shall be notified in writing within 10 calendar days. The written notification shall include the following information:

A. Old meter's hour reading.

B. Replacement meter's manufacturer name, model, and serial number if available and current hour reading on replacement meter.

C. Copy of receipt of new meter or of installation work order.

A copy of the meter replacement notification shall be maintained on site and made available to the Air Pollution Control District upon request. (Rule 69.4.1) (17 CCR §93115)

Verification: The project owner shall provide notification to the District as required by this condition and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-89 The owner or operator shall conduct periodic maintenance of this engine and add-on control equipment, if any, as recommended by the engine and control equipment manufacturers or as specified by the engine servicing company's maintenance procedure. The periodic maintenance shall be conducted at least once each calendar year. (Rule 69.4.1)

<u>Verification:</u> The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-90 The owner or operator of the engine shall maintain the following records on site for at least the same period of time as the engine to which the records apply is located at the site:

A. Documentation shall be maintained identifying the fuel as ARB diesel;

B. Manual of recommended maintenance provided by the manufacturer, or maintenance procedures specified by the engine servicing company; and

C. Records of annual engine maintenance, including the date the maintenance was performed.

These records shall be made available to the Air Pollution Control District upon request. (Rule 69.4.1)

<u>Verification:</u> The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-91 The owner or operator of this equipment shall maintain a monthly operating log containing, at a minimum, the following:

A. Dates and times of engine operation, indicating whether the operation was for maintenance and testing purposes or emergency use; and, the nature of the emergency, if known;

B. Hours of operation for all uses other than those specified above and identification of the nature of that use. (Rule 69.4.1) (17 CCR §93115)

<u>Verification:</u> The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-92 All operational and maintenance logs required by this permit shall be kept a minimum of 36 months from their date of creation unless otherwise indicated by the conditions of this permit. The records shall be maintained onsite for a minimum of 24 months from their date of creation. Records for the last 24 months of operation shall be made available to the Air Pollution Control District upon request. Records for operation for the last 25 to 36 months shall be made available to the Air Pollution Control District within 5 working days of request.

<u>Verification:</u> The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Additional General Conditions

AQ-93 All records required by these conditions shall be maintained on site for a minimum of five years and made available to the District upon request.

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

ACRONYMS

AAQS	Ambient Air Quality Standard
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
APCD	Air Pollution Control District (SDAPCD)
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMP	Air Quality Management Plan
AQIA	Air Quality Impact Assessment
ARB	California Air Resources Board
ARM	Ambient Ratio Method
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Technology
bhp	brake horsepower
Btu	British thermal unit
CAAQS	California Ambient Air Quality Standard
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CEM	Continuous Emission Monitor
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTG	Combustion Turbine Generator
CPM	(CEC) Compliance Project Manager
CVEUP	Chula Vista Energy Upgrade Project
DAHS	Data Acquisition and Handling System
DAS	Data Acquisition and Recording System
dscf	dry standard cubic foot

EIR	Environmental Impact Report
ERC	Emission Reduction Credit
FDOC	Final Determination Of Compliance
GCL	Gregory Canyon Landfill
GHG	Greenhouse Gas
gr	Grains (1 gr ≅ 0.0648 grams, 7000 gr = 1 pound)
GTE	Gas Turbine Engine
HAP	Hazardous Air Pollutant
HARP	Hotspots Analysis Reporting Program
hp	horsepower
H_2S	Hydrogen Sulfide
ISCST3	Industrial Source Complex Short Term, version 3
LAER	Lowest Achievable Emission Rate
lbs	pounds
LORS	Laws, Ordinances, Regulations and Standards
MACT	Maximum Achievable Control Technology
MCR	Monthly Compliance Report
mg/m^3	milligrams per cubic meter
MMBtu	Million British thermal units
m/s	meters per second
M&TS	Monitoring and Technical Services (SDAPCD)
MW	Megawatts (1,000,000 Watts)
NAAQS	National Ambient Air Quality Standard
NH_3	Ammonia
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
OGP	Orange Grove Project
OLM	Ozone Limiting Method
PDOC	Preliminary Determination Of Compliance
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter

PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSD	Prevention of Significant Deterioration
PTO	Permit to Operate
RATA	Relative Accuracy Test Audit
RDCN	Remote Data Collection Node
RMQ	Rosemary's Mountain Quarry
ROG	Reactive Organic Gases
SA	Staff Assessment (this document)
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SDAB	San Diego Air Basin
SDAPCD	San Diego Air Pollution Control District
SDG&E	San Diego Gas and Electric
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur
SR	State Route
T-BACT	Best Available Control Technology for Toxics
U.S. EPA	United States Environmental Protection Agency
$\mu g/m^3$	Microgram per cubic meter
VOC	Volatile Organic Compounds

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AIR APPENDIX A

Greenhouse Gas Emissions

Matthew Layton, P.E.

SUMMARY OF CONCLUSIONS

The Orange Grove Project (OGP) is a peaking project that would likely operate infrequently and the project's emissions per MWh are expected to be considerably lower than those of the existing power plant and other peaking power plants that the project would replace and, thus, would contribute to continued improvement of the overall WECC system GHG emission rate average. Moreover, even if it were not replacing higher GHG emitting power plants, it would be speculative to conclude that the project would result in a cumulatively significant GHG impact. Staff recommends reporting of the GHG emissions as the Air Resources Board develops greenhouse gas regulations and/or trading markets required by the California Global Warming Solutions Act of 2006 (AB 32). The project may be subject to additional reporting requirements and GHG reduction or trading requirements as these regulations become more fully developed and implemented.

Staff concludes that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be significant.

The Orange Grove Project, as a peaking project with an enforceable operating limitation less than 60% of capacity, is not subject to the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

INTRODUCTION

Greenhouse gas (GHG) emissions are not criteria pollutants, but they are discussed in the context of cumulative impacts. The State has demonstrated a clear willingness to address global climate change though research, adaptation and inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity consumption, and describes the applicable GHG standards and requirements.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies pertain to the control and mitigation of greenhouse gas emissions. Staff's analysis examines the project's compliance with these requirements.

Air Quality Appendix Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
State	
AB 32	California Global Warming Solutions Act of 2006. This act requires ARB to enact standards that will reduce GHG emission to 1990 levels. Electricity production facilities will be regulated.
SB 1368	Greenhouse Gas Emission Performance Standard. This regulation prohibits utilities from entering into long-term contracts with any baseload facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes CO_2/MWh (1,100 lbs CO_2/MWh)

GLOBAL CLIMATE CHANGE AND ELECTRICITY PRODUCTION

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps substantially) to that change. Man-made emissions of greenhouse gases, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature finds that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Cal. Health & Safety Code, Sec. 38500, Division 25.5, Part 1).

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p.5). In 2003, the Energy Commission recommended that the state require reporting of greenhouse gases (GHG) or global climate change[1] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (ARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020.[2] To achieve this, ARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December, 2007, and plans to establish statewide emissions caps by economic "sectors" in 2008. By January 1, 2009, ARB will adopt a scoping plan that will identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB staff will then draft regulatory language to

[1] Global climate change is the result of greenhouse gases, or emissions with global warming potentials, affecting the energy balance, and thereby, climate of the planet. The term greenhouse gases (GHG) and global climate change (GCC) gases are used interchangeably.

[2] Governor Schwarzenegger has also issued Executive Order S-3-05 establishing a goal of 80% below 1990 levels by 2050.

implement its plan and will hold additional public workshops on each measure, including market mechanisms (ARB 2006). The regulations must be effective by January 1, 2011 and mandatory compliance commences on January 1, 2012.

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission, are identified in the California Climate Action Team's Report to the Governor (CalEPA 2006). Others are being established by ARB during its 2008 scoping plan development process. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). It is possible that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the "most bang for the buck"). For example, the ARB proposes a 40% reduction in GHG from the electricity sector, even though that sector currently only produces 25% of the state GHG emissions. In response, in September 2008 the Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches, and identified regulation points should ARB decide that a multi-sector cap and trade system is warranted.

The Energy Commission's 2007 Integrated Energy Policy Report (IEPR) also addresses climate change within the electricity, natural gas, and transportation sectors. For the electricity sector, it recommends such approaches as pursuing all cost-effective energy efficiency measures and meeting the Governor's stated goal of a 33% renewable portfolio standard.

SB 1368[3], also enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibits California utilities from entering into long-term commitments with any baseload facilities that exceed the Emission Performance Standard of 0.500 metric tonnes CO_2 per megawatt-hour[4] (1,100 pounds CO_2/MWh). Specifically, the Emission Performance Standard applies (EPS) to baseload power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.[5] If a project, instate or out of state, plans to sell baseload electricity to California utilities, the utilities will have to demonstrate that the project complies with the EPS. Baseload is defined as units which operate at a capacity factor higher than 60% of the year. As a project with a permit operating restriction of less than 60% of the year, OGP is not required to comply with the SB 1368 EPS.

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap and trade market to reduce

[3] Public Utilities Code § 8340 et seq.

[4] The Emission Performance Standard only applies to carbon dioxide, and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[5] See Rule at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

greenhouse gas emissions in the west. The timelines for the implementation of this program are similar to those of AB 32, with full roll-out beginning in 2012. And as with AB 32, the electricity sector has been a major focus of attention.

PROJECT GREENHOUSE GAS EMISSIONS

The generation of electricity using fossil fuels can produce air emissions known as greenhouse gases in addition to the “criteria air pollutants” that have been traditionally regulated under the federal and state Clean Air Acts. Greenhouse gas emissions contribute to the warming of the earth’s atmosphere, leading to climate change. For fossil fuel-fired power plants, these include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 - unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment, and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very large relative global warming potentials.

CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. **Greenhouse Gas Table 1** shows what the proposed project, as permitted, could potentially emit in greenhouse gases during construction. All emissions are converted to CO_2-equivalent and totaled.

Greenhouse Gas Table 1
OGP, Estimated Potential Construction Greenhouse Gas Emissions

Construction Element	CO_2 Equivalent (metric tonnes) [a]
Site Grading and Preparation	165
Main Site Construction – Civil, Mechanical, Electrical	504
Gas Line Construction	134
Construction Total	803

Source: Staff estimate based on construction data provided by the applicant (OGE 2008a), where staff used the latest ARB GHG emission factor recommendations (ARB 2008a).
a. One metric tonne (mt) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms

OPERATIONS

The proposed OGP would be a peaking power facility that would be limited to an equivalent of 3,200 hours of full load operation. The two General Electric LM6000 gas turbines are fired with natural gas. There will also be a small amount of GHG emissions from the diesel-fueled emergency and fire pump engines and hydrofluorocarbons (HFCs) emissions from chiller cooling fluid leaks; however, no new sulfur hexafluoride containing equipment has been proposed for the project. The employee and water delivery traffic GHG emissions are also included in the operating emission GHG totals, even though they are negligible in comparison with the gas turbine GHG emissions.

Greenhouse Gas Table 2 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very large relative global warming potentials.

Greenhouse Gas Table 2
OGP, Estimated Potential Operating Greenhouse Gas Emissions – Permit Basis

	Project Emissions (metric tonnes [a] per year)	Global Warming Potential [b]	CO_2 Equivalent (metric tonnes per year)
Carbon Dioxide (CO_2)	161,744	1	161,744
Methane (CH_4)	2.8	21	58
Nitrous Oxide (N_2O)	0.3	310	95
Hexafluoride (SF_6)	0	23,900	0
Hydrofluorocarbons (HFCs)	0.003	1,300[c]	4
Perfluorocarbons (PFCs)	0	7,850 [d]	0
Total Project GHG emissions – mt CO_2–eq per year			161,901
Total Project MWh per year (net) [e]			307,264
Project CO_2 Emissions Performance - mt CO_2/MWh			0.526
Project GHG Emissions Performance - mt CO_2-eq/MWh			0.527

Sources: OGE 2008a and TRC 2008f where staff updated the natural gas GHG emissions factors to use the latest ARB recommendations (ARB 2008a).
a. One metric tonne (mt) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
b. The global warming potential is a measure of the chemicals' warming properties and lifetime in the atmosphere relative to CO_2. The value shown is based on the emission factors from the California Climate Action Registry's Appendix to the General Reporting Protocol: Power Utility Reporting Protocol (CCAR 2005).
c. The proposed chiller cooling fluid HFC-134a has a warming potential of 1,300.
d. This figure is an average GWP for the two PFCs, CF_4 and C_2F_6.
e. This reflects net base load power for 3,200 hours.

The proposed project would be permitted, on an annual basis, to emit over one hundred sixty thousand metric tonnes of CO_2-eq per year if operated at its maximum permitted level, but this is extremely unlikely as shown by comparing actual capacity factors from other comparable San Diego County peaker facilities (see Air Quality Section).

The expected maximum annual GHG criteria emissions are well below the permitted maximum value shown in GREENHOUSE GAS Table 2, which would occur if the project were to operate at maximum permitted levels. The maximum annual GHG emissions based on a 13.7% capacity factor, used for criteria pollutant mitigation, would be approximately 60,000 metric tons of CO2-eq per year; and the maximum expected long term emissions would be less than 22,000 metric tonnes of CO2-eq per year (assuming a 5% project life capacity factor). As the capacity factor decreases so does the project's overall efficiency which will cause the actual project GHG emissions to increase slightly per MWh. For comparison the similarly designed Riverside Energy

Resource Center had actual GHG emissions of 0.542 mt CO_2-eq /MWh from their LM600 gas turbines for a two year period that operated with an overall capacity factor of just less than 5%.

Since the project's permit limits operation to less than a 60% annual capacity factor, it does not need to meet the EPS of 0.500 mt CO_2/MWh.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses three kinds of impacts: construction, operation, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time.

CONSTRUCTION IMPACTS

Staff does not believe that the small GHG emission increases from construction activities would be significant for several reasons. First, the period of construction will be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meet the latest emissions standards would further minimize greenhouse gas emissions since staff believes that the use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

The proposed OGP promotes the state's efforts to increase electrical generation efficiencies and reduce the amount of natural gas used by electricity generation and, thus, greenhouse gas emissions. As the 2007 Integrated Energy Policy Report (CEC 2007a) noted:

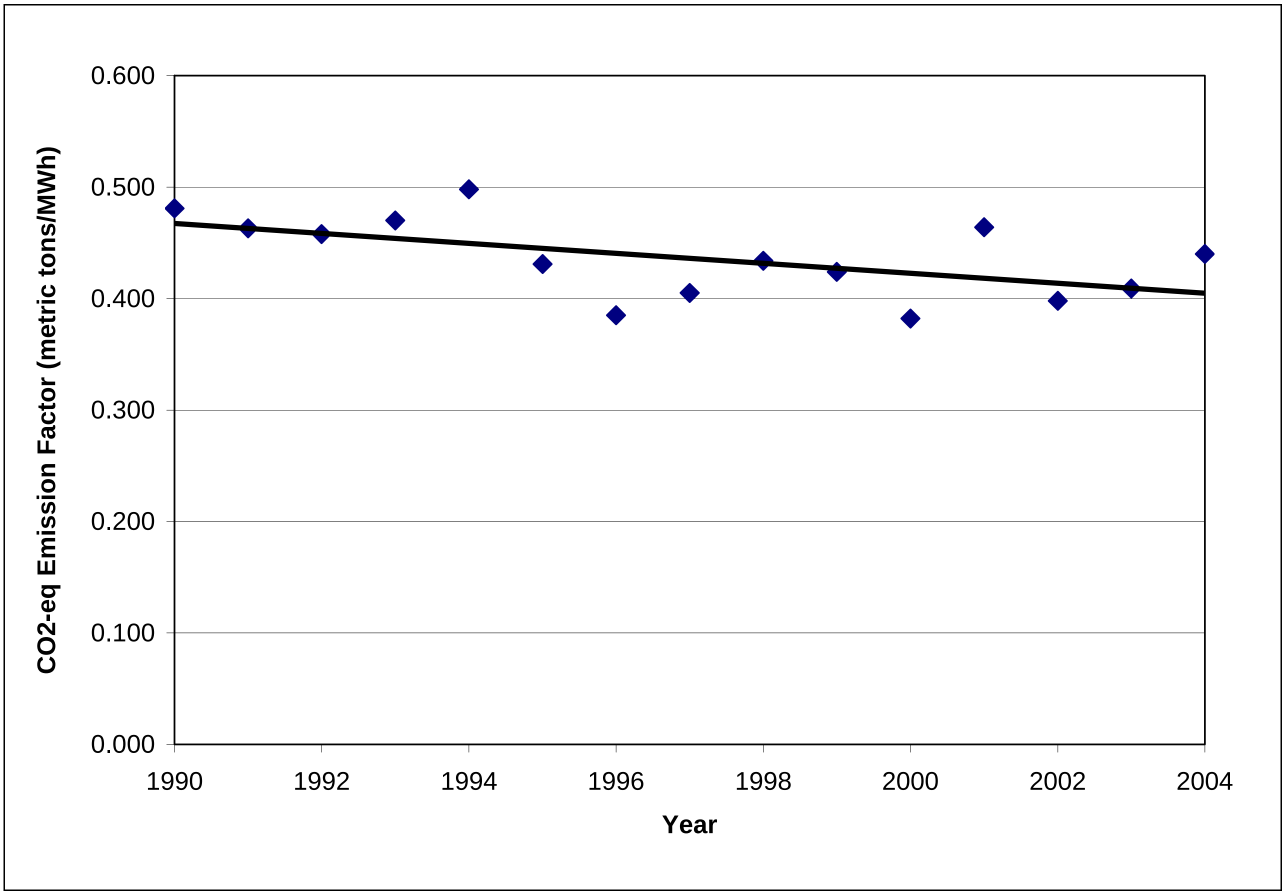
> *New natural gas-fueled electricity generation technologies offer efficiency, environmental, and other benefits to California, specifically by reducing the amount of natural gas used—and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants.… The 2003 and 2005 IEPRs noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient power plants. (CEC 2007a, p. 184)*

Thus, in the context of the Energy Commission's Integrated Energy Policy Report, the OGP likely replacement of older existing plant capacity furthers the state's strategy to promote efficiency and reduce fuel use and GHG emissions.

System Averages

Because most power plants are interconnected to a utility grid, and in turn to the Western Electricity Coordinating Council (WECC), it is also important to look at the proposed project in the context of all electricity systems delivering electricity to California consumers. **Air Quality Figure 1** shows the trends in GHG emission rates for each MWh consumed in California. From 1990 to 2004, California electricity became almost 20% "cleaner" on a GHG basis. This improvement was due in part to retirements of dirtier, less efficient plants, despite electricity demand growth of almost 20% from 1990 to 2004. Note that the trend line, a linear regression of the annual GHG emission rates, is a better representation of the statewide GHG emission rates than the actual number in any one year. GHG emissions and electricity consumption can vary from year to year due to variations in the availability of hydroelectric power, economic activity, and anomalous events such as the energy crisis of 2000-2001 and unusually warm weather conditions in 2004.

Greenhouse Gas Figure 1
GHG Emissions per Megawatt-hour Consumed in California



Source: ARB 2008b and CEC 2007b.

The proposed project, if it operates at its maximum permitted level, would have a GHG emission rate (approximately 0.53 mt CO_2-eq/MWh) that is greater than the system wide average (the trend line in 2004 is approximate 0.400 mt CO_2-eq/MWh). However, the project should not result in a net increase in global GHG emissions because it would likely operate to replace energy from existing less efficient peaking power sources in the San Diego Area and, thus, would contribute to continued improvement of the overall WECC system GHG emission rate average.

However, even considering if the project cannot be directly attributed to replace higher-emitting existing local power plant capacity, it would be difficult to conclusively determine whether the project would result in a net increase in GHG emissions, for several reasons. Because of the complex interchange among facilities that make up California's electricity system, it is possible that this project could displace electricity that may have otherwise been generated by more GHG intensive facilities, such as out-of-state coal plants or local old inefficient peaking units. Additionally, facilities of this nature, with quick-start capabilities, are needed to support California's efforts to increase use of renewable resources.

Indeed, the 2007 Integrated Energy Policy Report identifies natural gas generation as a "complementary strategy to meet greenhouse gas emission reductions." It fills the gap that cannot be currently served by renewable generation, provides system stability to integrate new renewable generation, and may ultimately be necessary to displace imported coal generation, which has much higher GHG emissions. As stated in the 2007 IEPR:

> *Growth in natural gas used to generate electricity may exceed even these estimates under certain greenhouse gas reduction measures. For example, scenario analyses calculated that if a $60 per ton price were attached to* CO_2 *emissions, projected levels of coal-generated electricity in the WECC would decline by about 30-4% in 2020. As a result, natural gas burned to generate electricity in California would increase by about 20-70% depending on the amount of preferred resources. …*
>
> *Reducing the amount of coal used to generate electricity with a combination of preferred resources and natural gas and in the context of $60 per ton of carbon charge increases natural gas use in California and throughout the WECC.*
>
> *Natural gas is and will remain the major fuel in California's supply portfolio and must be used prudently as a complementary strategy to reduce greenhouse gas emissions. Not only does the state have a mandate to cut greenhouse gas emissions, it also has a responsibility to provide a reliable and affordable fuel source for home and business use. (CEC 2007a, p. 186)*

Therefore, even though we can identify how many gross GHG emissions are attributable to a project, it is difficult to determine whether this will result in a net increase of these emissions, and, if so, by how much. It would, thus, be speculative to conclude that any given electricity generation project results in a cumulatively significant adverse impact resulting from greenhouse gas emissions.

Additionally, the quickly evolving GHG regulatory efforts, currently being formulated, may shortly establish the best *fora* for addressing GHG emissions from power plants rather than attempting to do so on an ad hoc or plant-by-plant basis. The applicant's goal is to have the OGP project operational by summer 2009. ARB will have set forth each sector's reduction requirements as of January of 2009, followed by the adoption of specific regulations by January of 2011.

Ultimately, ARB's AB 32 regulations will address both the degree of electricity generation emissions reductions, and the method by which those reductions will be achieved, through the programmatic approach currently under its development. That regulatory approach will presumably address emissions not only from the newer, more efficient, and lower emitting facilities licensed by the Commission, but also the older, higher-emitting facilities not subject to any GHG reduction standard that this agency could impose. This programmatic approach is likely to be more effective in reducing GHG emissions overall from the electricity sector than one that merely relies on displacing out-of-state coal plants ("leakage") or older "dirtier" facilities.

As ARB codifies accurate GHG inventories and methods, it may become apparent that relative contributions to the inventories may not correlate to relative ease and cost-effectiveness of the GHG emission reductions necessary to achieve the 1990 GHG level. Though it has not yet been determined, the electricity sector may have to provide less or more GHG reductions than it would have otherwise been responsible for on a pro-rata basis.

To facilitate ARB's future regulatory regime, staff recommends Condition of Certification **GHG-1**, which requires the project owner to report the quantities of relevant GHGs emitted as a result of electric power production until such time that AB 32 is implemented and its reporting requirements are in force. It is possible that no reporting will ever be required by this condition if ARB's reporting requirements are in force prior to the first calendar year of plant operation. However, staff believes that **GHG-1**, with the reporting of GHG emissions, will enable the project to be consistent with the policies described above and the regulations that ARB adopts, and provide the information to demonstrate compliance with any applicable EPS that could be enacted in the next few years. The GHG emissions to be reported in **GHG-1**, are carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, HFCs and PFCs emissions that are directly associated with the production and transmission of electric power.

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts" (CEQA Guidelines § 15355). "A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts" (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This entire assessment is a cumulative impact assessment. The project alone would not be sufficient to change global climate, but would emit greenhouse gases and therefore has been analyzed as a potential cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LORS

The project will be subject to compliance with AB 32 requirements once they are determined by ARB. How the project will comply with these ARB requirements is speculative at this time but compliance will be mandatory. The GHG emissions reporting requirement under **GHG-1** does not imply that the project, as defined, will comply with the potential reporting and reduction regulations being formulated under AB 32. The project may have to provide additional reports and GHG reductions, depending on the reporting requirements of the new regulations expected from ARB.

Since this power project would be permitted for less than a 60% annual capacity factor, and would be considered a peaking facility, it is not subject to the requirements of SB 1368 and the Emission Performance Standard.

NOTEWORTHY PUBLIC BENEFITS

No greenhouse gas related noteworthy public benefits have been identified.

CONCLUSIONS

The OGP project would only be used when called upon to supply power during peak load demands. It would be speculative to conclude that the project would result in a cumulatively significant GHG impact. AB 32 emphasizes that GHG emissions reductions must be “big picture” reductions that do not lead to “leakage” of such reductions to other states or countries. If a gas-fired power plant is not built in California, electricity to serve the load will come from another generating source. That could be renewable generation like wind or solar, but it could also be from higher carbon emitting sources such as out-of-state coal imports or old inefficient peaking units that are a still a significant part of the resource mix that serves California.

Staff does not believe that the small GHG emission increases from construction activities would be significant for several reasons. First, the period of construction will be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meet the latest emissions standards would further minimize greenhouse gas emissions since staff believes that the use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. For all these reasons, staff concludes that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be significant.

Since this power project would be permitted for less than a 60% annual capacity factor, and could be considered a peaking facility, it is not subject to the requirements of SB 1368 and the Emission Performance Standard.

The Staff has proposed a condition of certification, **GHG-1**, which is the Commission Greenhouse Gas interim reporting requirement that is applicable until the facility falls under AB 32 required reporting.

PROPOSED CONDITIONS OF CERTIFICATION

Staff recommends the following condition of certification to address the greenhouse gas impacts associated with the construction and operation of the OGP project.

STAFF CONDITION

GHG-1 Until the California Global Warming Solutions Act of 2006 (AB 32) is implemented, the project owner shall either participate in a GHG registry approved by the CPM, or report on a annual basis to the CPM the quantity of greenhouse gases (GHG) emitted as a direct result of facility electricity production.

The project owner shall maintain a record of fuels types and carbon content used on-site for the purpose of power production. These fuels shall include but are not limited to each fuel type burned: (1) in combustion turbines, (2) HRSGs (if applicable) or auxiliary boiler (if applicable), (4) internal combustion engines, (4) flares, and/or (5) for the purpose of startup, shutdown, operation or emission controls.

The project owner may perform annual source tests of CO_2 and CH_4 emissions from the exhaust stacks while firing the facility's primary fuel, using the following test methods or other test methods as approved by the CPM. The project owner shall produce fuel-based emission factors in units of lbs CO_2 equivalent per MMBtu of fuel burned from the annual source tests. If a secondary fuel is approved for the facility, the project owner may also perform these source tests while firing the secondary fuel.

Pollutant	Test Method
CO_2	EPA Method 3A
CH_4	Protocol: EPA Method 18 (VOC measured as CH_4)

As an alternative to performing annual source tests, the project owner may use the Intergovernmental Panel on Climate Change (IPCC) Methodologies for Estimating Greenhouse Gas Emissions (MEGGE). If MEGGE is chosen, the project owner shall calculate the CO_2, CH_4 and N_2O emissions using the appropriate fuel-based carbon content coefficient (for CO_2) and the appropriate fuel-based emission factors (for CH_4 and N_2O).

The project owner shall convert the N_2O and CH_4 emissions into CO_2 equivalent emissions using the current IPCC Global Warming Potentials (GWP). The project owner shall maintain a record of all SF_6 that is used for replenishing on-site transformers. At the end of each reporting period, the project owner shall total the mass of SF_6 used and convert that to a CO_2 equivalent emission using the IPCC GWP for SF_6. The project owner shall maintain a record of all PFCs and HFCs that are used for replenishing on-site refrigeration and chillers directly related to electricity production. At the end of each reporting period, the project owner shall total the mass of PFCs and HFCs used and convert that to a CO_2 equivalent emission using the IPCC GWP.

On an annual basis, the project owner shall report the CO_2 and CO_2 equivalent emissions from the described emissions of CO_2, N_2O, CH_4, SF_6, PFCs, and HFCs.

Verification: The project annual greenhouse gas emissions shall be reported, as a CO2 equivalent, by the project owner to a climate action registry approved by the CPM, or to the CPM as part of the fourth Quarterly or the annual Air Quality Report, until such time that GHG reporting requirements are adopted and in force for the project as part of the California Global Warming Solutions Act of 2006.

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